CONTRACTOR REPORT

PIER
Public Interest Energy Research
CALIFORNIA ENERGY COMMISSION

Environmentally-Preferred Advanced Generation

Durability of Catalytic Combustion Systems

APPENDIX I: Market Requirements Development

Gray Davis, *Governor*

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CALIFORNIA ENERGY COMMISSION

Prepared for:

CALIFORNIA ENERGY COMMISSION

Avtar Bining, ***Contract Manager***

Research & Development Office

Prepared by:

Energy Nexus Group, a Subsidiary of Onsite Energy Corp.

Jim Schlatter
Troy Kinney

CATALYTICA ENERGY SYSTEMS
Mountain View, CA

Mike Batham, ***Program Lead***

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PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Environmentally-Preferred Advanced Generation
- Energy-Related Environmental Research
- Strategic Energy Research.

What follows is the topical report for the **Durability of Catalytic Combustion Systems Project**, conducted by Catalytica Energy Systems. The report is entitled **"Marketing Requirements Development"**. This project contributes to the Environmentally-Preferred Advanced Generation program.

For more information on the PIER Program, please visit the Commission's Web site at: http://www.energy.ca.gov/research/index.html or contact the Commission's Publications Unit at 916-654-5200.

EXECUTIVE SUMMARY

Catalytica Energy Systems, Inc. (CESI) was awarded by the California Energy Commission (CEC) a project addressing the reliability, availability, maintainability, and durability (RAMD) of catalytic combustion systems for gas turbines. Catalytic combustion addresses the objective of reducing pollutant emissions from gas turbine generator sets burning clean natural gas. It falls under the CEC PIER identified subject area of Environmentally Preferred Advanced Generation (EPAG).

As part of the CEC PIER project, critical commercialization issues were to be identified and assessed under a task titled Market Requirements Development. These issues included stakeholder perceptions, key public and customer benefits, and recommendations for potential market entry strategies.

Background

This report documents the methodology and results of the three primary tasks of the Market Requirements Development component of the CEC PIER scope of work. Those primary tasks are:

- Review of Commercialization Requirements
- Quantification of Critical Public and Private Sector Benefits to the State of California
- Extrapolation of Benefits Beyond California and Recommendations for Initial Target Markets

This report is comprised of three primary sections each pertaining to the tasks described above.

Review of Commercialization Requirements

This task, described in detail in Section 1 of this report, identified commercialization issues, assessed the perceptions of key stakeholders, recommended approaches to working with key stakeholders, and described steps to improve the probability of successful technology transfer of the results of the proposed PIER project to commercial applications.

Methodology

The approach used in the review of commercialization requirements consisted of targeted telephone interviews with what were identified to be a sample of key stakeholders in the development, commercialization and utilization of catalytic combustion systems for industrial gas turbines.

Companies contacted and interviewed included those that manufacture or package industrial size (1-10 MW) gas turbine systems, develop gas turbine based projects, supply emission control equipment, and various other stakeholders. Also contacted in the course of this task were environmental regulatory agencies, permitting consultants and energy policy "influencers".

Each telephone interview included a discussion of target markets and applications, minimum customer requirements, design and integration issues and maintenance issues.

Results

In the completion of this task it was clear that the level of understanding and familiarity with Xonon ranges from very familiar to limited knowledge of low emission combustion systems. The general sentiment from most interviewees was that there was some degree of uncertainty with regard to both the commercial readiness of Xonon and the emissions regulations that would require a product like Xonon.

The specific perspectives of stakeholders are examined in more detail in the sections that follow. Selected noteworthy comments and perspectives are listed below:

- Those in the gas turbine manufacturer and environmental regulatory communities had the relatively highest understanding of the development and commercialization status of Xonon. Both manufacturers and environmental regulators were aware of demonstration of Xonon at Silicon Valley Power and the positive results.
- Gas turbine manufacturers acknowledged existing development programs with Catalytica and identified issues such as development costs and an uncertain regulatory environment that does not provide a clear incentive to move forward with a Xonon based product at this time.
- Environmental regulatory agencies identified emission limit trends that are relevant to the need for products like Xonon for the DG market (e.g., SB 1298 in California and eastern Texas regulations and guidelines that will eventually put the same emissions limits on DG as there currently are on central station plants; NSR being reviewed; and emission limits that may favor CHP).
- Project developers, while familiar with low emission combustion approaches, had acknowledged very little experience with Xonon and were uncertain about its current commercial availability and performance guarantees.
- Project developers had also expressed some initial confusion about current emission requirements and the control technologies on which current limits are based.
- Project developers supported the development of any technology that would open markets that are currently "closed" to them due to strict emissions limitations.
- Project developers and gas turbine developers stressed strongly their aversion to risk and perceived uncertainties associated with Xonon (e.g., not certain of actual commercial rollout date, warranty issues, perceived high financial risk and the desire to limit technical risks.

Table ES-1 summarizes the feedback form the stakeholder groups interviewed.

Table ES-1: Stakeholder Perceptions of Xonon and Related Commercialization Issues

Developers and End-Users	Original Equipment Manufacturers (OEMs)	Environmental Regulators	Regulatory and Government
• Fear risk • Can't afford to "wait" for product • Are uncomfortable with product and technology uncertainties – e.g., warranties • Feel they are taking substantial financial risk and seek to limit technology risk • Have historically preferred larger projects • Recognize competition with reciprocating engines at low end of range. • See near term market opportunity for capacity needs in certain applications	• Desire ownership of technology • Perceive the current emissions regulations environment as unfavorable • Prefer the availability of pollution prevention approaches over exhaust clean up • Active in innovative combustion development • Perceive durability as issues • Recognize the engineering difficulties of integrating Xonon in specific gas turbines • Question the incentive to invest if emissions regulations will require exhaust cleanup regardless of turbine emission levels • Possess uneasiness in reliance on an outside supplier playing a key role in a critical component of their machines • Active in evaluating other approaches besides Xonon • Seek to reduce risk by leveraging external funding to demonstrate new developments • Unable to make a firm commitment to commercialize at this point	• Consider themselves as forcing technology, not prescribing it • Desire emissions controls technologies to be proven in practice • Track extensively development efforts and demonstrations • Project DG emissions becoming an issue • Have advocated regulations favorable to "clean" technologies • Support rapid permitting of DG but don't want it any dirtier than typical new plant (i.e., new combined cycle) • Recognize the value of CHP with its high total efficiency and fuel utilization • Initiating CHP outreach programs to facilitate CHP (e.g., US EPA) • Monitoring EPA New Source Review (NSR) --- impact of CHP at an existing site still not clear	• Making energy policy a state and national priority • Consider greenhouse gas emission limits a high priority but political issue • Feel strongly that CHP and other high efficiency should play an important role energy policy • Have subsidized clean technologies • Considering if CHP should get the same treatment as clean technologies • Have been lobbied by the CHP community for changes to tax laws and rate issues

Recommendations

The project team recommends the following possible approaches in working in partnership with the key stakeholders to help ensure support for the commercialization of Xonon.

Project Developers/End-users:

- Develop consensus that CHP applications offer the best opportunity for gas turbines in this size range given the positioning with competing DG options (low simple cycle efficiencies and heat recovery possibilities)
- Work with multiple developers (avoid exclusive arrangements)
- Work with large ESCO's and unregulated utility affiliates (utilities still have strong resistance to baseload CHP)
- Look at current market activity (institutional and university/school markets seem ripe) and work with multiple developers to cultivate those markets (e.g., create standard "CHP package" for certain sectors)
- Help to standardize sales and permitting approach to limit transactional and project development costs

Original Equipment Manufacturers (OEMs)

- Work with OEMs to secure external development funding as currently perceived high development costs make for a difficult internal sale when seeking internal funding
- Identify GT OEMs who are looking to take market share from leading companies; these OEMs may see that the upside potential justifies the development costs
- Clearly identify criteria for moving along the development path to commitment to commercialize and eventual full product rollout
- Jointly develop development programs consistent with those criteria

Environmental Regulators

- Make certain they are current with recent developments and pending milestones
- Track emissions regulatory actions in environmentally constrained geographical areas
- Show advantages of Xonon equipped gas turbines over other fossil fueled DG options (e.g., diesel gensets)
- Advocate determining output-based emissions limits that recognize the total high efficiency of CHP and give appropriate credit for heat recovery
- Advocate Xonon as a critical component that allows for the most economic application of CHP while still ensuring environmentally responsible siting
- Work with environmental regulatory community in outreach programs that communicate benefits of CHP
- Push for new rapid permitting procedures of CHP projects

Regulatory/Government

- In the development of state and national energy policy, take steps to ensure that CHP is a primary component of the strategy given its inherent high fuel utilization efficiency
- Look to get CHP considered a "clean" preferable technology along with renewables and fuel cells.

- Work with or join CHP advocacy groups (USCHPA) that support revised tax treatment, government R&D, real open access, and other policies to help further develop the CHP market
- Inform that given the technical and market risks associated with Xonon, continued government R&D support is required

Quantification of Critical Public and Private Sector Benefits to California

This task, described in Section 2 of the report, shows the impact of Xonon technology on expected future market penetration of distributed generation in California and quantifies the energy, economic, and environmental benefits of the Xonon technology to the California market.

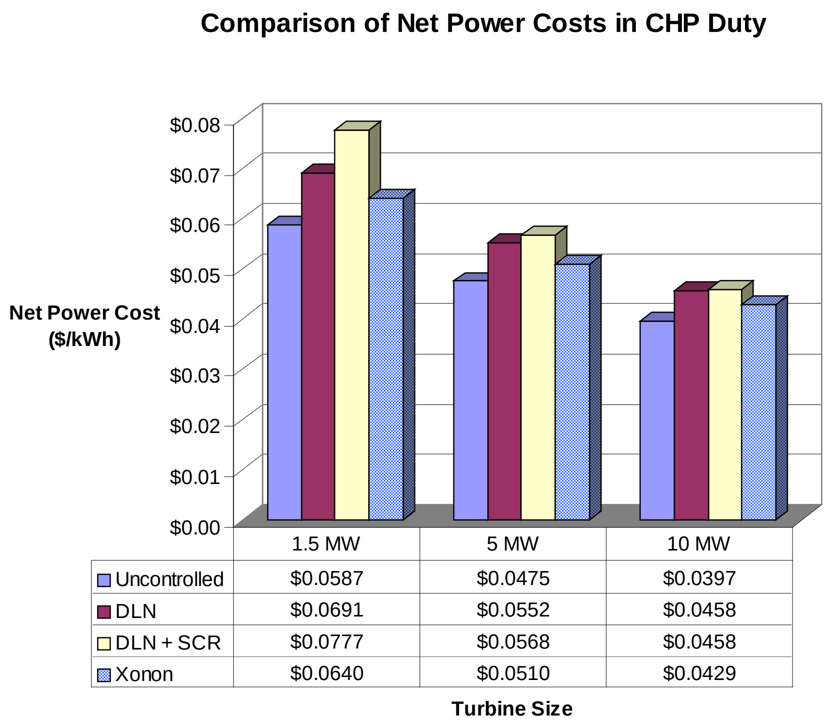
Methodology

In order to quantify critical benefits, estimates of market penetration and characterizations of Xonon and competing technologies had to be determined. The project team used prior work funded by state of California agencies on combined heat and power and distributed generation penetration into the California market as a basis for the calculations of key benefits. Two recent studies have been completed on the likely penetration of distributed generation applications in California. They are ONSITE Energy's "Market Assessment of Combined Heat and Power in the State of California", sponsored by the California Energy Commission, and Distributed Utility Associates' "Air Pollution Impacts Associated with Economic Market Potential of Distributed Generation in California", sponsored by the California Air Resources Board and the California Environmental Protection Agency. Technology cost and performance options were developed for representative gas turbine systems of 1 MW, 5 MW, and 10 MW. The market impact of Xonon technology with respect to future market penetration of distributed generation in California and the energy, economic and environmental benefits of Xonon to California from this enhanced penetration were calculated.

Results

Figure ES-1 shows the comparison of costs for an uncontrolled system, DLN, DLN plus SCR, and Xonon. All of the hidden costs are incorporated into these cost estimates except for the uncontrolled case that is included for reference only – not as a realistic alternative for nonattainment areas.

Figure ES-1 Comparison of Net Power Costs for CHP Systems as a Function of Emissions Control Technology



	1.5 MW	5 MW	10 MW
Uncontrolled	$0.0587	$0.0475	$0.0397
DLN	$0.0691	$0.0552	$0.0458
DLN + SCR	$0.0777	$0.0568	$0.0458
Xonon	$0.0640	$0.0510	$0.0429

Using Xonon, cumulative market penetration has a net increase of 856 MW compared to the DLN+SCR alternative. This is shown in Table ES-2.

Table ES-2: Comparison of the Impacts of DLN/SCR and Xonon on CHP Market Penetration

CHP Size Category	Cumulative Penetration in MW
Market Penetration with DLN plus SCR	
1-5 MW	10
5-20 MW	522
> 20 MW	4,056
Total	4,587
Market Penetration with Xonon	
1-5 MW	66
5-20 MW	757
> 20 MW	4,620
Total	5,443
Added Market Penetration due to Xonon	
1-5 MW	57
5-20 MW	235
> 20 MW	565
Total	856

Economic and energy savings due to the increased market penetration attributed to Xonon are described in detail in Section 2. The total sum of benefits is over $10 billion for the Xonon based market penetration case. This figure is nearly $3 billion greater than in the DLN/SCR penetration case. The net present value today, using a 10% discount rate, of the increased future stream of savings due to Xonon is over $1 billion. These savings correspond directly to increased productivity for California's commercial and industrial sectors – money that can go into newer processes, more equipment, more workers, etc., rather than into meeting energy bills. The total net energy savings from CHP using Xonon technology rather than the DLN/SCR alternative over the forecast period are on the order of 0.3 quads. Energy savings represent a social benefit in lowering the pressure on fuel and electricity supply and infrastructure, thereby providing lower prices for all consumers. In addition, lowered energy use helps to reduce CO2 emissions that contribute to global warming. These impacts are difficult to quantify, but represent at least part of the motivation behind social goals, evident in California, to increase the efficiency of energy utilization.

The DLN+SCR and Xonon technologies compared for this analysis were set to provide the same level of NOx emissions; therefore, one might expect that there is no change in environmental impact. However, the CHP systems, either with DLN/SCR or Xonon, provide an environmental benefit compared with the emissions produced by central station power plants and the on-site boiler emissions. To the extent that the Xonon technology encourages greater CHP market penetration, these environmental benefits are correspondingly increased.

Two cases were assessed in the determination of environmental benefits. The first case used the values for average California central station emissions and boiler emissions from the CARB/Distributed Utility Associates study. Table ES-3 shows the NO_x emissions impacts of the two emissions control strategy market penetrations using the CARB/DUA study values for avoided generation and boiler emissions.

Table ES-3: NOx Emission Reductions for the DLN/SCR and Xonon CHP Market Penetration Scenarios based on Backing out Existing Boiler and Generation Technology

CHP Category by Size	Cumulative Penetration in MW	CHP Emissions tpy	Boiler Emissions tpy	Utility Emissions tpy	Net Change tpy
SCR Case					
1-5 MW	10	4.4	29.4	4.4	-29.4
5-20 MW	522	191.7	1,091.6	237.9	-1,137.8
> 20 MW	4,056	1,396.0	7,969.3	1,847.4	-8,420.7
Total	4,587	1,592.2	9,090.3	2,089.7	-9,587.8
Xonon Case					
1-5 MW	66	30.5	201.5	30.2	-201.3
5-20 MW	757	277.9	1,581.8	344.7	-1,648.7
> 20 MW	4,620	1,590.4	9,078.9	2,104.6	-9,593.1
Total	5,443	1,898.7	10,862.2	2,479.5	-11,443.0

In the second case, the benefits of the two CHP market penetration scenarios were based on the avoided emissions from new generation and boilers. Table ES-4 shows this comparison. The CHP generation emissions remain the same, though these emissions are no longer lower than the avoided central station generation emissions from new sources. However, the CHP emissions are lower than the avoided boiler emissions, though not as dramatically as in the existing technology comparison used in the CARB analysis. The net decrease in NO_x emissions due to the use of Xonon compared to DLN/SCR in this case is 476 tons/year.

Table ES-4: NOx Emission Reductions for the DLN/SCR and Xonon CHP Market Penetration Scenarios based on Backing out New Boiler and Generation Technology

CHP Category by Size	Cumulative Penetration in MW	CHP Emissions tpy	Boiler Emissions tpy	Utility Emissions tpy	Net Change tpy
SCR Case					
1-5 MW	10	4.4	10.5	1.7	-7.7
5-20 MW	522	191.7	389.7	91.5	-289.4
> 20 MW	4,056	1,396.0	2,845.0	710.5	-2,159.6
Total	4,587	1,592.2	3,245.2	803.7	-2,456.8
Xonon Case					
1-5 MW	66	30.5	71.9	11.6	-53.1
5-20 MW	757	277.9	564.7	132.6	-419.4
> 20 MW	4,620	1,590.4	3,241.1	809.5	-2,460.2
Total	5,443	1,898.7	3,877.8	953.7	-2,932.8

Conclusions

Based on a comparison of this analysis, Xonon technology can produce net power costs that are only 7-9% more costly than an uncontrolled turbine. In addition, Xonon achieves the same NO_x emissions levels as the DLN plus SCR option at costs that are 7-21% lower.

Based on a CHP market analysis approach originally developed for CEC in a prior project, Xonon equipped gas turbines can achieve an additional 855 MW of market penetration in California between 2001 and 2017, compared to gas turbines using DLN plus SCR to achieve the same level of emissions reduction. These added systems represent an 18.5% increase in the CHP market for California.

The total sum of user cost savings is over $10 billion for the Xonon based market penetration case. This figure is nearly $3 billion greater than in the DLN/SCR penetration case. The net present value today of the increased future stream of savings due to Xonon is over $1 billion. These savings correspond directly to increased productivity for California’s commercial and industrial sectors. The total energy savings from CHP using Xonon technology over the forecast period equal about 2 quads of energy. The differential energy savings due to Xonon are on the order of 0.3 quads.

The market penetration scenario based on the use of Xonon technology reduces total NO_x emissions by 11,443 tpy compared to the existing mix of power generation and commercial and industrial boilers in California. Comparing emissions to new central station and boiler emission factors produces a less dramatic reduction (2,932 tpy) in total NOx emissions. The higher market penetration rates for Xonon based CHP systems compared to DLN/SCR systems results in lower emissions attributable to Xonon – even though the Xonon and DLN/SCR technologies have equivalent emissions levels at each site.

The Xonon technology will help the California economy by increasing the productivity of industrial and commercial facilities, encouraging stability of fuel and power markets by reducing demand pressure, and encouraging an accelerated reduction of air pollution in the state.

U.S. Market for Industrial Gas Turbines with Xonon Catalytic Combustion

This task, described in Section 3 of this report, provides a qualitative assessment of the US market for industrial sized gas turbine based systems with catalytic combustion. The Report identifies potential initial markets for commercialization. The market for power generation and distributed generation equipment extends well beyond the boundaries of California. It is the entire market that justifies investment in research and development and in production facilities.

Methodology

The technical approach used in this assessment and development of recommendations consisted of the following components:

1. Review a database of non-utility generators to assess commercial/institutional and industrial CHP history and activity
2. Identify commercial/institutional and industrial applications best suitable for 1-10 MW gas turbine CHP systems
3. Identify states with high potential for 1-10 MW CHP applications and need for low emissions. Desirable attributes include:
    - relatively high electric rates
    - emissions regulations that require ultra-low NO_x levels (<2.5 ppm)
    - favorable history of implementing CHP projects

Results

The screening criteria for selecting target markets included the following:

- States with relatively high electric rates
- States with emissions regulations that require ultra-low NO_x levels (<2.5 ppm)
- States and customer sectors with a favorable history of implementing CHP projects in the 1-10 MW size range

Table ES-5 provides a summary of the screening results based on the approach and data presented above on the existing CHP market.

Table ES-5 Target Market Screening Results

States with High Electric Rates	States in Environmentally Constrained Areas	States with Favorable History with CHP	Customer Sectors with Favorable History with CHP
Alaska California Connecticut Hawaii Massachusetts New Hampshire New Jersey Rhode Island Vermont	Arizona California Connecticut Delaware Illinois Indiana Louisiana Maine Maryland Massachusetts New Hampshire New Jersey New York Pennsylvania Rhode Island Texas Vermont Virginia Wisconsin	California New Jersey Michigan Connecticut Illinois Massachusetts Texas	Commercial Office Buildings Colleges/Universities Hospitals Government Facilities Prisons Food Industry Miscellaneous Manufacturing Stone/Clay/Glass Chemical Industry

Conclusions

The results of this qualitative assessment indicate that the best opportunities for 1-10 MW gas turbine based CHP systems with catalytic combustion are in markets in California, the Northeast states of Connecticut, Massachusetts, New Hampshire, New Jersey, Rhode Island, and Vermont, and East Texas. These states can be characterized as having both high electric rates and strict emissions limits on power generation equipment.

While several commercial and industrial sectors were identified as having an existing base of CHP in the 1-10 MW range, we recommend that the large institutional sectors of Colleges/Universities, Hospitals, Government Facilities and Prisons be initially targeted. These customers tend to have lower economic hurdle rates than industrial customers do and have a tendency to value the societal benefits catalytic combustion offers. These recommendations are summarized in Table ES-6

Table ES-6 Recommended Target Markets

Regions	Customer Sector
California Connecticut Massachusetts New Hampshire New Jersey Rhode Island Vermont East Texas	Colleges/Universities Hospitals Government Facilities Prisons

Factors Impacting Commercialization and Ultimate Market Penetration

The overall results of this project identified issues and concerns of key stakeholders, quantified the significant benefits to California from the potential utilization of catalytic combustion on industrial sized gas turbines, and identified potential markets to target in the early phases of commercialization. Catalytic combustion offers compelling benefits and is entering commercial production at a time with notable market opportunities.

While most analysts agree that CHP can be a very competitive energy option in a fully restructured market, there are a variety of institutional and market hurdles that are currently limiting CHP growth in the transition. Factors that could lead to more aggressive market penetration in the future include:

- Technology Improvements
- Recognition of CHP Benefits
- CHP Outreach Initiatives
- Increased Marketing Efforts

1. REVIEW OF COMMERCIAL REQUIREMENTS

1.1 Introduction

Catalytica Energy Systems, Inc. (CESI) requested a scope of work from ONSITE Energy to address Commercialization issues as a sub-contractor in their response to California Energy Commission (CEC) RFP No. 500-97-503 as part of the Public Interest Energy Research Program (PIER).

Catalytica Energy Systems, Inc. (CESI) was awarded by California Energy Commission (CEC) a project addressing the reliability, availability, maintainability, and durability (RAMD) of catalytic combustion systems for gas turbines. Catalytic combustion addresses the objective of reducing pollutant emissions from gas turbine generator sets burning clean natural gas. It falls under the CEC PIER identified subject area of Environmentally Preferred Advanced Generation (EPAG).

As part of the project team, Energy Nexus Group, a subsidiary of Onsite Energy Corp., was to identify critical commercialization issues, quantify key public and customer benefits, and provide recommendations for demonstration planning and market entry strategies.

This report documents the results of Energy Nexus Group's efforts. Energy Nexus Group drew on its developed knowledge, expertise, and experience in the development and commercialization of advanced energy systems. The effort described in this report identified commercialization issues, the perceptions of key stakeholders, recommended approaches to working with key stakeholders, and steps to improve the probability of successful technology transfer of the results of the proposed PIER project to commercial applications.

This report is divided into three primary sections related directly to the three primary tasks of Energy Nexus Group's contracted scope of work:

- Review of Commercialization Requirements
- Quantification of Critical Public and Private Sector Benefits to the State of California
- Extrapolation of Benefits Beyond California and Recommendations for Initial Target Markets

1.2 Market Background

There has been remarkable growth in worldwide prime mover (gas turbines and reciprocating engines) demand during the past decade. This is driven by several factors, including growth in developing nations and a demonstrable market shift away from conventional large-scale thermal power plants toward use of prime movers for power generation—especially larger (over 30 MW) gas turbines in simple- and combined-cycle configurations.

The application of gas turbines for stationary power generation has grown considerably over the past decade and is projected to continue to grow in the future. Strong gas turbine demand is based on several key product attributes associated with combustion turbines (CTs)—high efficiency in combined-cycle configurations; low capital, operating, and maintenance costs; high reliability and availability; shortened lead time for permitting and construction; and low emissions.

While exhaust emissions from natural gas-fueled and distillate-fueled CTs are low, continued environmental pressure is resulting in permitted emission limits in some areas being below what is commonly achievable even with advanced dry low NO_x (DLN) combustors. An alternative combustion approach, catalytic combustion, offers the potential to achieve ultra-low NO_x emission levels without the complications and cost of post-combustion emission controls.

1.2.1 Current Gas Turbine Market

Continued market growth is expected for natural gas-fueled prime movers, primarily turbines and reciprocating engines. Gas turbines in both simple- and combined-cycle systems have accounted for the vast majority of power generation capacity added in the last five years in both international and U.S. markets. These are predominantly central station power plants greater than 50 MW. In short, large gas turbines have become the power generation technology of choice. This trend is expected to continue over the foreseeable future. Several factors contribute to the strong position of gas turbine-based power generation and the likely role turbines will play in the future:

1. An optimistic outlook for the supply and price of natural gas
2. Technology advances that produced substantial improvements in efficiency and emissions
3. Emissions regulations that could favor gas turbine projects over traditional fossil-fueled steam turbines
4. Attractive initial capital costs and reduced time and cost for power plant permitting and installation, compared to traditional power plants.

Figure 1-1 shows the total 1999 worldwide orders for engines and turbines in sizes over 1 MW (based on data reported by Diesel and Gas Turbine Worldwide). The figure clearly shows a substantial increase in demand for large turbines over 30 MW in size.

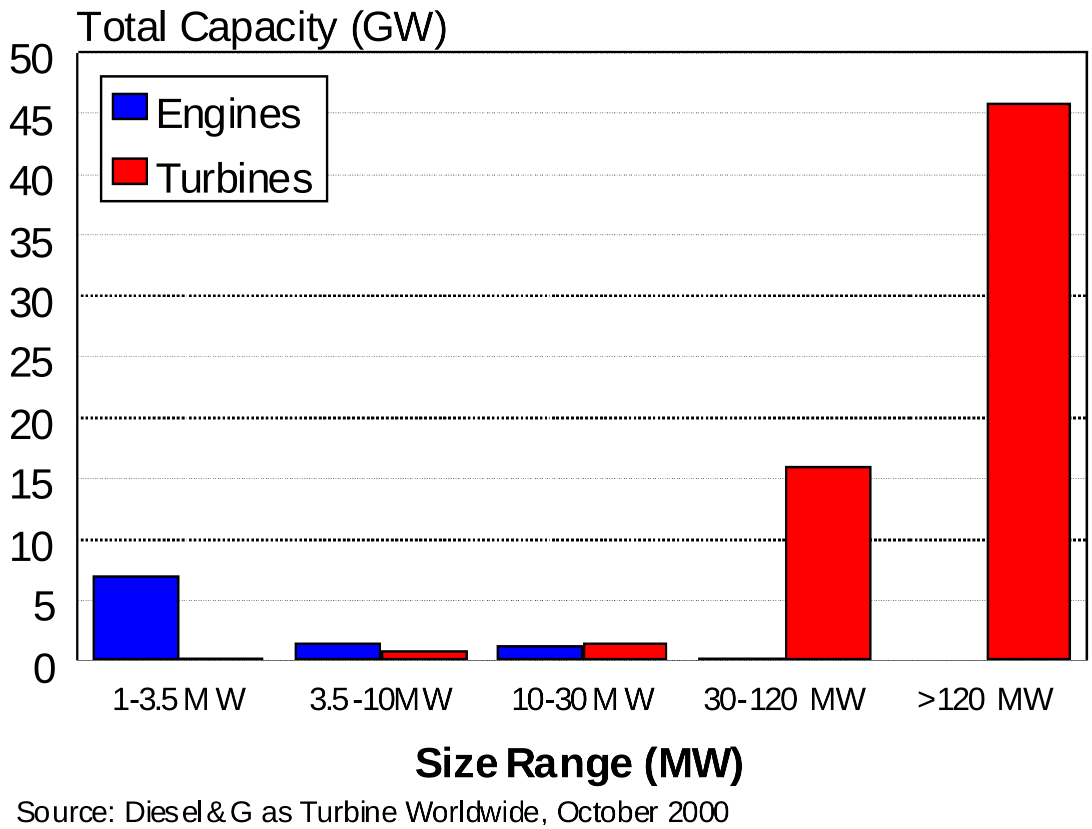


Figure 1-1: Worldwide Prime Mover Orders (Over 1 MW)

Total gas turbine orders amounted to over 64 GW of capacity during this one-year period. This represents a significant level of acceleration in gas turbine orders compared to 1997-1998, when just over 32 GW of orders were reported. Using a nominal price of $400 per kW for gensets, new gas turbine annual sales fall in the range of $12 to $25 billion. This is consistent with market information reported by Forecast International as shown in Fig. 1-2).

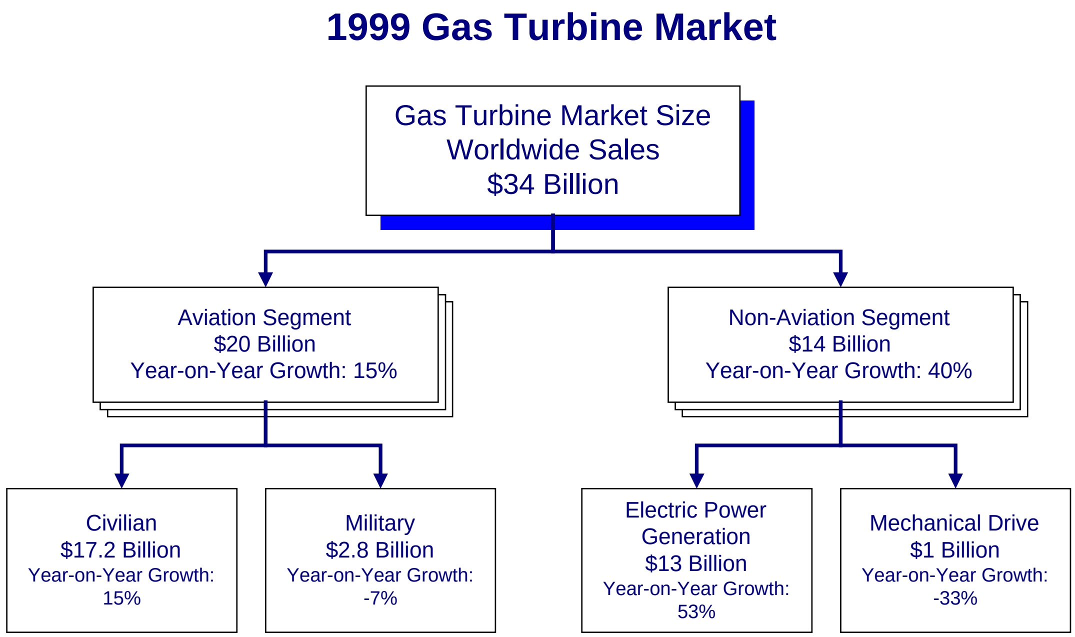


Figure 1-2: Estimated Gas Turbine Market (Forecast International, 1999)

Gas turbines cover a broad spectrum of sizes, from 10's of kW for microturbines up to nearly 200 MW. However, most of the order volume—on a capacity basis—resides above 60 MW (89.8%) and nearly 96% lies above 30 MW as illustrated in Table 1-1.

On a unit basis, there were a total of 875 gas turbines ordered during this one-year period. Strong demand existed above 60 MW, followed by the 1 to 10 MW, 30 to 60 MW, and 10 to 30 MW segments.

Table 1-1: Gas Turbine Orders By Size Range (1999)

Year	**Orders (GW)**	**Share (% of Capacity)**	**# Units**	**Share (% of Units)**
1-10 MW	1.07	1.7%	313	35.8%
10-30 MW	1.46	2.3%	75	8.5%
30-60 MW	3.99	6.2%	103	11.8%
Over 60 MW	57.73	89.8%	384	43.9%
Totals:	64.25		875	

Source: Diesel and Gas Turbine Worldwide (over 1 MW)

The 1999 turbine order level represents a significant increase from historical levels. Gas turbine orders as reported by Diesel and Gas Turbine Worldwide over the recent past are shown in Table 1-2. One can observe from the table that turbine orders have grown by a factor of 5 to 10 in the past fifteen years. The long-term trend indicates an increase in the “average” turbine unit size. In actuality, the gas turbine market is bi-modal, with a large number of units sold between 1-10 MW and over 60 MW. The interest in over 60 MW size units has continually expanded over the past decade and is the main driver in increased total GW of demand.

Table 1-2: Gas Turbine Order Trend (1984-1999)

Year	Total Orders (GW)	Total Orders (Units)
1984	6.5	435
1988	17.0	466
1994	27.43	796
1998	33.20	754
1999	64.25	875

Source: Diesel and Gas Turbine Worldwide (over 1 MW)

The overall market situation supports a conclusion that gas turbine demand has dramatically changed over the past ten to fifteen years. Annual growth in new orders is about 13% per year on a compounded basis (excluding 1999, where orders exploded by over 90% in one year). New gas turbine orders will likely remain strong into the future and continue at levels well above historical levels.

Increased turbine demand is primarily due to a distinct market shift away from large, coal-fired central-station thermal power plants toward 100-500 MW combustion turbine power plants (simple- or combined-cycle, fueled by natural gas or liquid fuels). Gas turbines have gained the upper hand in the inter-industry competition with thermal power plant producers, in part by increasing their upper size limit. The dominance of combustion turbines over conventional thermal power plants will continue until fuel price differentials (natural gas to coal or distillate to coal) change significantly.

While the market and business climate is quite favorable for large gas turbines, gas turbines in the distributed generation market (1-10 MW) face greater challenges. Fundamental market drivers favor large gas turbine power plants because of lower capital costs and shorter construction and permitting lead times than traditional fossil-fueled steam turbines. Large combined-cycle systems have efficiencies in the 50-58% range, based on the fuel’s lower heating value (LHV). The environmentally clean nature of the these plants is evidenced by their ability to achieve 9 ppmv of nitrogen oxides (NO_x) emissions without exhaust treatment and lower than 3 ppmv with post-combustion control technologies.

A natural facet of the combustion turbine market evolution is an increase in the number of market participants and expansion of the value of gas turbine products sold. All this has occurred while unit prices ($/kW) have trended downward and efficiency values have increased. The market has shifted more to an intra-industry competition for sales and market share between different gas turbine producers and project developers. Under these circumstances, unique product features and benefits—that is, differentiators—will become increasingly important in providing an edge during the sales process. Advanced technology such as catalytic combustion can play a role in a company's strategic product planning.

On the smaller end of the spectrum—that is, below 30 MW—gas turbines face strong inter-industry competition from reciprocating engines. This competition accelerates at unit sizes below 10 MW and becomes exponential with decreasing size (Table 1-3). For example, in the 1 to 2 MW size-range, reciprocating engines outsell gas turbines by nearly a 33:1 margin.

Table 1-3: Gas Turbine and Reciprocating Engine Orders (1999, 1-30 MW)

Year	Turbine Orders (MW)	Engine Orders (MW)
1-10 MW	1,070	8,350
10-30 MW	1,046	1,157

Source: Diesel and Gas Turbine Worldwide (over 1 MW)

Below 1 MW, nearly all of the demand for stationary prime movers has been satisfied by liquid-fueled and gaseous-fueled reciprocating engines. The total demand for power generation engines below 1 MW is estimated to be about 23,000 MW. Figure 1-3 shows data from Parkinson Associates on their estimation of worldwide demand for stationary power generation engines. These figures demonstrate a significant growth market for smaller (under 10 MW) gas turbines if they can become more competitive or preferred power generation options. The interest in microturbines is directed at the nearly quarter million reciprocating engines sold in the 75 kW and less size range (as well as in new market growth opportunities).

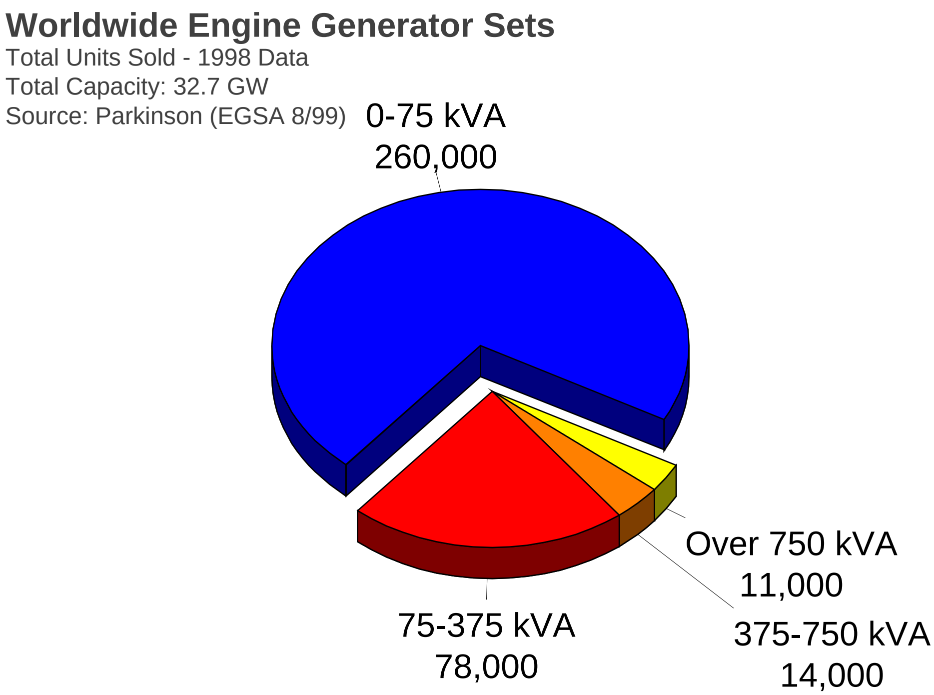


Figure 1-3: Worldwide Reciprocating Engine Sales

For smaller gas turbines to gain market share, they need a combination of product improvements, improved competitive pricing, and possibly external market factors such as environmental drivers working to their benefit. Gas turbines with advanced technologies such as catalytic combustion would seemingly offer substantial emission/environmental impact differentiation relative to the majority of reciprocating engine products in the market.

1.2.2 Competitive Positioning of Small Gas Turbines

Gas turbines start to lose their clear advantage at smaller sizes. In the industrial market segment (3.5-30 MW), worldwide sales of gas turbines and reciprocating engines are about equal. The size range below 5 MW is dominated by reciprocating engines, both natural gas and diesel fueled. As gas turbines decrease in size, they exhibit higher specific capital costs ($/kW) and lower efficiencies. For example, in the 2-5 MW size range, gas turbines and reciprocating engines have comparable capital costs, but the reciprocating engines have substantially better efficiencies, between 37% and 42% (LHV), versus 32% or lower typical of comparably sized gas turbines (Figure 1-4). The new Mercury 50™ gas turbine, a recuperated 4-MW machine manufactured by Solar Turbines Incorporated, is the exception to this relationship; this unit has an efficiency of about 40%. In the 2-MW and smaller range, reciprocating engines are priced lower than gas turbines and are considerably more efficient. Figure 1-5 shows the price and efficiency of simple-cycle gas turbine products up to 25 MW. Figure 1-6 compares the capital costs of reciprocating engines (RE) and gas turbines (CT" in the figure) up to 7 MW.

The distinct advantages of small gas turbines over reciprocating engines include higher quality recoverable energy, lower emissions, lower maintenance requirements, and higher power density (kilowatt or horsepower per unit of air flow and machine volume). Recoverable energy refers to the amount of energy that can be recovered from the turbine exhaust stream, usually in the form of clean, high-temperature heat. Higher quality recoverable energy allows for a wider range of thermal energy (for example, high-pressure steam) to be generated if needed. Consequently, many small gas turbines are currently deployed in combined heat and power configurations where this recoverable energy can be used and higher total fuel efficiency can be achieved. In addition, gas turbines often have less frequent requirements for routine maintenance compared to reciprocating engines, which need periodic oil and spark-plug maintenance.

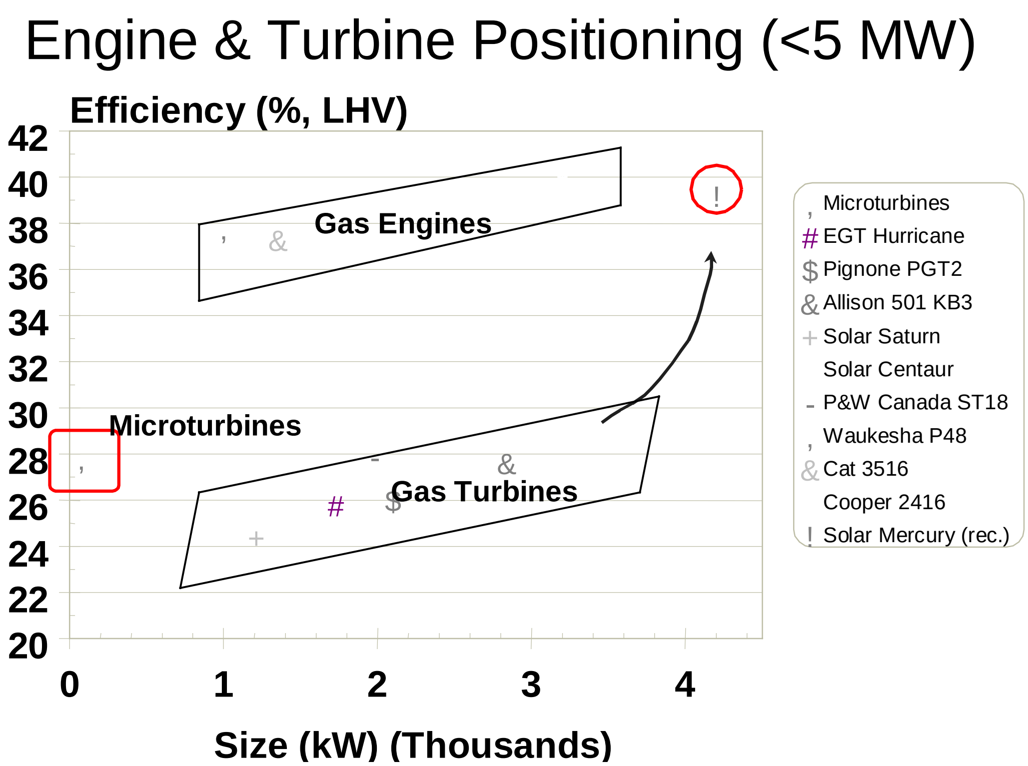
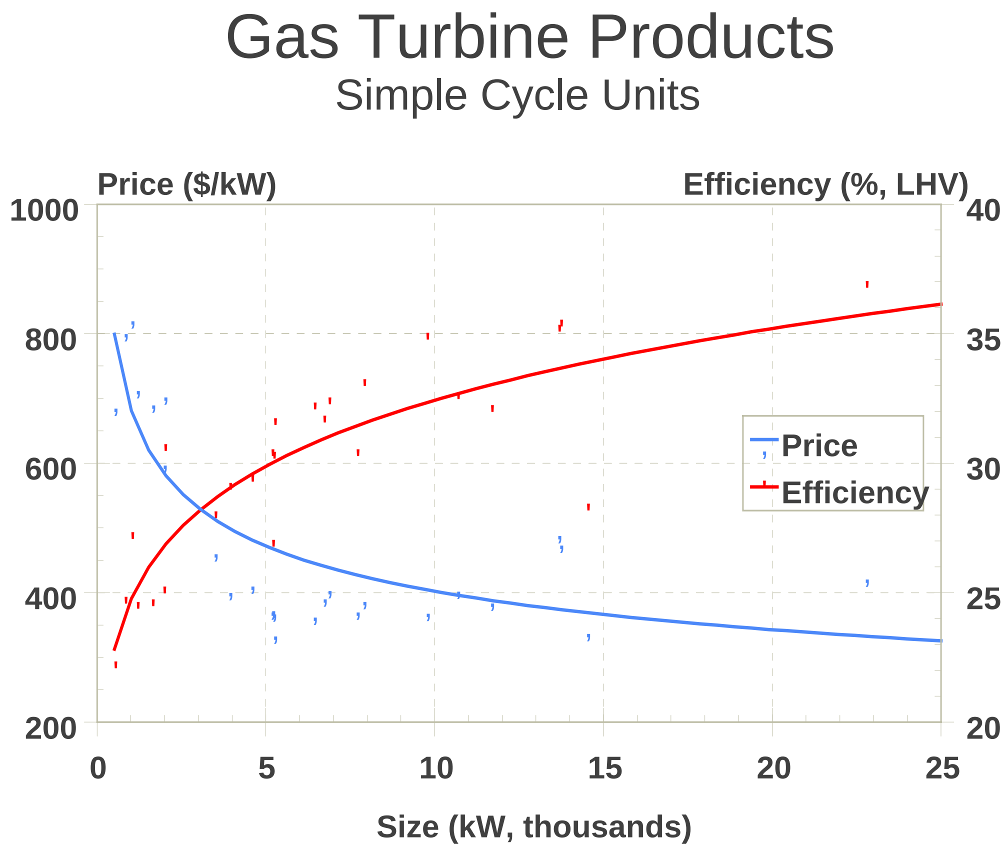
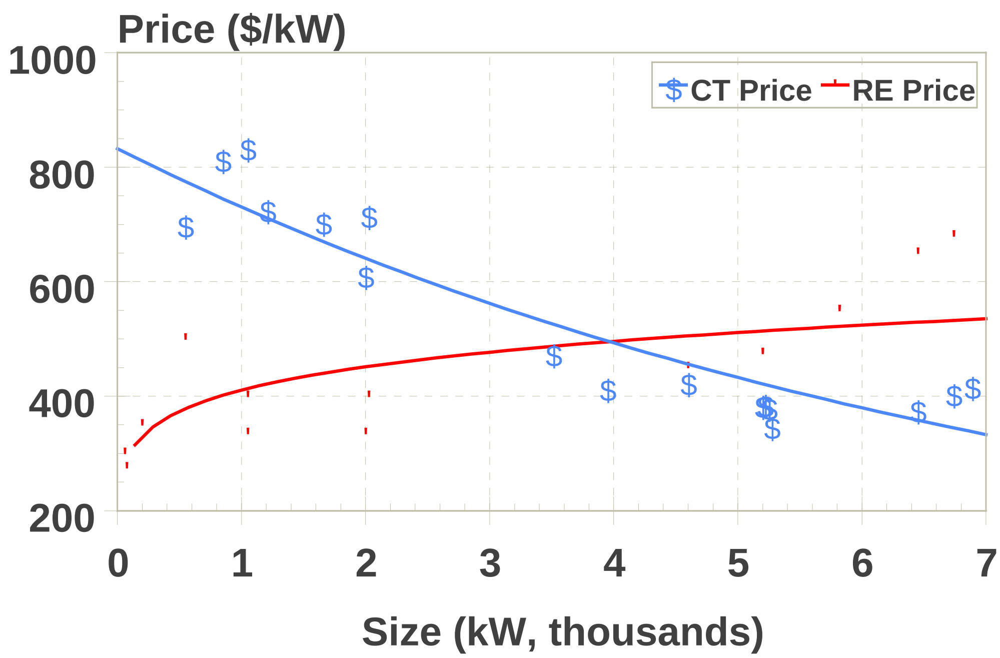


Figure 1-4: Small Gas Turbine Product Positioning
Source: GTI



Actual purchase prices may vary due to market conditions and other factors
Source: Gas Turbine World/GRI

Figure 1-5: Small Gas Turbine Products



Actual purchase prices may vary due to market conditions and other factors.
Prices do not include gas compressors (if required).
Source: Gas Turbine World/SFA Pacific/GRI

Figure 1-6: Capital Cost Comparison of Small Gas Turbines with Reciprocating Engines

Manufacturers and providers of small gas turbines have long recognized the competitive positioning of their products and have initiated developments to enhance their position in the evolving power market. R&D and technology improvements for small gas turbines have focused primarily on the testing and integration of new components including recuperators, advanced hot-section materials, and low emission combustion systems.

1.2.3 Emissions as a Market Driver

The environmental permitting process is a relatively complex process—particularly in the U.S. Figure 1-7 provides an overview of the regulatory situation. This begins with the Clean Air Act (CAA and its amendments) and flows down through the requirements of the National Ambient Air Quality Standards (NAAQS). From the NAAQS program, the severity of emissions as a driver depends largely on whether or not an area is in attainment or not for various NAAQS species (e.g., ozone, CO).In addition, it depends on the degree of non-attainment (if applicable), and the size of the unit and its operational characteristics and/or potential to emit.

For new units, customers will likely be required to comply with either state or local guidelines for new sources. In attainment areas, this will likely mean satisfying BACT (Best Available Control Technology). In non-attainment areas, this will likely mean satisfying LAER (Lowest Achievable Emission Rate) limits, which may include the need to obtain emission offsets.

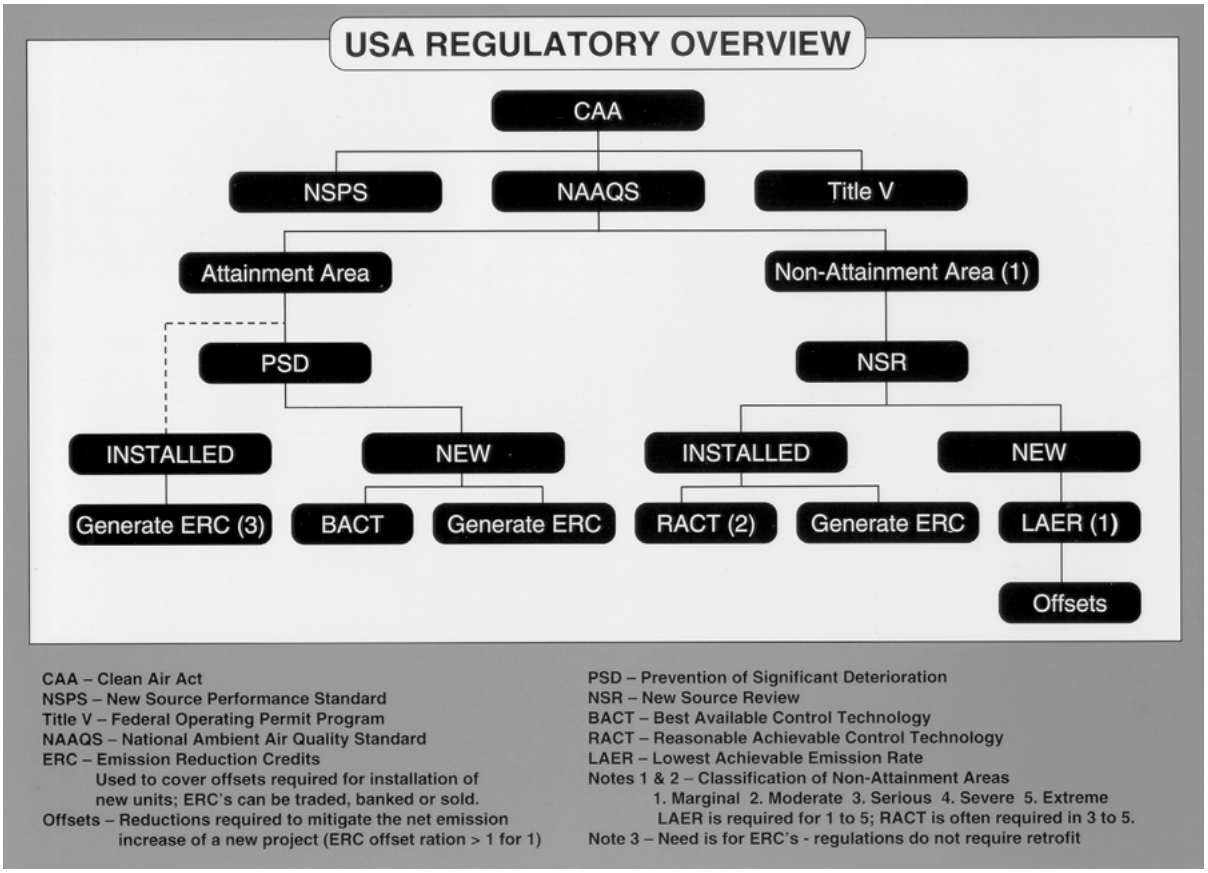


Figure 1-7: Environmental Regulation Overview
Source: Catalytica

Figure 1-8 provides a graphical representation of ozone non-attainment areas in the U.S. This situation changes periodically due to efforts to reduce regional emissions as well as local weather phenomenon. Changes in the NAAQS regulatory standard are also a key consideration.

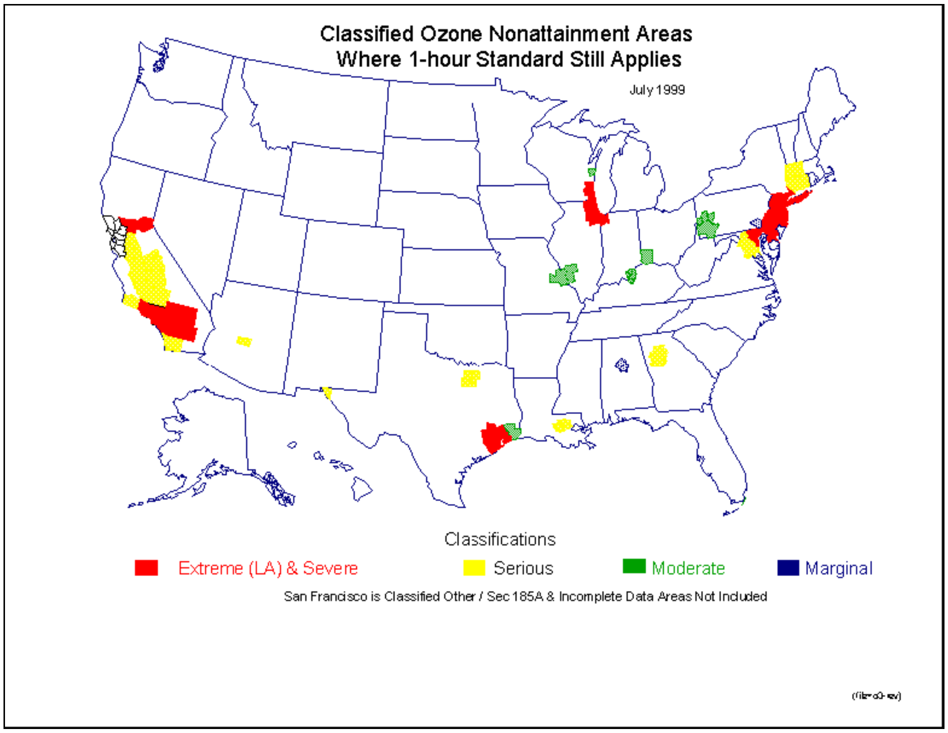


Figure 1-8: US Ozone Non-attainment Areas
Source: EPRI TR-113743/GRI-99/0264 (EEA)

Table 1-4 provides a summary of the threshold limits for new and modified emission sources depending on the degree of non-attainment. Also shown is the level of emission offsets required. Offsets are required reductions in emissions that must accompany the production of emissions from new sources. For example, for every ton of emissions from the new source, more than a ton must be reduced from other sources. The effect is a net reduction. The offset ratio is the ratio of tons of reduction required to tons produced from the new source. State or local regulations can be more stringent.

Table 1-4: NAAQS Classifications

Nonattainment Classification	**Threshold for New Source(1)(tons per year)**	**Threshold for Modified Source(1)(tons per year)**	**Offset Ratio**
Ozone Transport Region(2)	100 tpy	40 tpy	1.15:1
Moderate	100 tpy	40 tpy	1.15:1
Serious	50 tpy	25 tpy	1.2:1
Severe	25 tpy	25 tpy	1.3:1
Extreme	10 tpy	25 tpy	1.5:1
Attainment Area	100-250 tpy	40 tpy	N/A
Source: EPRI TR-113743/GRI-99/0264 (EEA)			

(1)The CAA definition of a "source" includes essentially all NO_x sources at the site in determining if the facility or "source" is above the threshold. In addition, the limit applies to maximum potential emissions. States have the option to set limits for still smaller sources.

(2)The Ozone Transport Region (OTR) is made up of 12 northeastern states/areas: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and the District of Columbia. This threshold applies to sources in all those states in any areas that are not more strictly classified.

BACT and LAER have been used over the years as a technology forcing mechanism to push for increasingly lower emission levels from new sources in attainment and non-attainment regions. This has resulted in the introduction of many new emission control technologies, including DLN for gas turbines. However, there is growing concern on the equity and effectiveness of this approach since it increasingly penalizes new technologies while encouraging the operation of older, higher polluting systems. There is likely to be an increasing trend toward incentive-based systems in the future as a means of providing more options for cost-effectively meeting NAAQS limits.

1.2.3.1 Recent Distributed Generation Emissions Developments in California and Texas

Recent air quality requirements in California and Texas have reflected a movement toward uniform emissions limits from all distributed generation sources. These limits are output-based (e.g., lb/MW-hr) and make it clear that air regulators would prefer that Distributed Generation (DG) units be as clean as the lowest emitting, highest efficiency central station plants, i.e., new gas turbine combined cycle installations. Brief summaries of the California requirements (SB 1298) and Texas (Texas Natural Resource Conservation Commission (TNRCC) Air Quality Standard Permit for Electric Generating Units) are presented below.

California Senate Bill 1298

California SB 1298 requires the California Air Resources Board (CARB), on or before January 1, 2003, to adopt a certification program and uniform emissions standards for distributed generation that are currently exempt from district permitting requirements, and would require that those standards reflect best performance achieved in practice by existing electrical generation equipment.

CARB has adopted on November 15, 2001 a two-phased approach with limits for specific applications in Phase 1 to begin in January 2003 and uniform limits in Phase 2 to begin in January 2007, regardless of technologies. Table 1-5 illustrates the new limits.

Table 1-5: SB 1298 Two-Phase Limits

2003 Emissions Limits (lb/MW-hr) – January 2003

Pollutant	***Power Production Only (PPO)***	***PPO equivalent ppm level(1)***	***Combined Heat and Power (CHP)***	***CHP equivalent NOx ppm level(1)***
NOx	0.5	9	0.7	15
CO	6.0	200	6.0	200
VOC's	1.0		1.0	

2007 Emissions Limits (lb/MW-hr) – January 2007

Pollutant	***Emissions Standard***	***Equivalent ppm level (1)***
NOx	0.07	1.5
CO	0.10	3.0
VOC's	0.02	

(1) Based on a representative 5 MW gas turbine with 11,300 Btu/kW-hr heat rate and 8000 hours of operation

The District's Guidelines for NOx based on recent BACT determinations are shown in Table 1-6. Beginning in 2007, all DG technologies regardless of configuration will be held to 0.07 lb/MW-hr NOx, 0.10 lb/MW-hr CO, and 0.02 lb/MW-hr VOCs. There are currently no commercially available technologies that guarantee 0.07 lb/MW-hr NOx.

Table 1-6: SB 1298 District Guidelines for NOx

Technology Category	***NOx Control Technique and Emissions Level (ppm @ 15% O2 or g/bhp-hr)***	***NOx Emission Level (lb./MW-hr)***
Combustion Turbine (12-50 MW)	Selective Catalytic Reduction (SCR) or SCONOx to 3 ppm	0.20
Combustion Turbine (3-12 MW)	SCR to 5 ppm	0.25
Combustion Turbine (<3 MW)	SCR to 9 ppm	0.50
Microturbine (<150 MW)	Combustion modifications	Power only: 0.50 CHP: 0.70 Combined with wind/solar: 1.0
Central Station Power Plant with BACT	SCR to 2.5 ppm	0.05
Reciprocating Engine with fossil fuel	Natural gas rich-burn engine with nonselective catalytic reduction and O2 controller or Natural Gas lean-burn engine with SCR to 0.07 g/bh-hr (rich-burn) and 9 ppm lean-burn	0.5
Reciprocating Engine with landfill or digestor gas	Lean burn technology to 0.6 g/bhp-hr	1.9

The goal of the standards is "equivalence to BACT for central station plants."

TNRCC Air Quality Standard Permit for Electric Generating Units

The TNRCC issued a new standard permit for small electric generating units (<10 MW). It was the intention of TNRCC to create a standard permit that would allow for a streamlined permitting method to encourage the use of clean generation technologies. The standard permit contains emissions limits more stringent than the emissions limits under Title 30 Texas Administrative Code Section 106.512 (30 TAC Section 106.512).

Similar to California SB 1298, the standard permit contains requirements to certify emissions of NO_x on the basis of lb/MW-hr output. It also sets technology-neutral standards that are intended to ensure the DG emission limits are consistent with new central station power plants, and attempts to credit the efficiency benefits of CHP. What is unique about the new standard permit is that standards are based upon whether the generator is located in the West Texas Region or East Texas Region. The NO_x limits under the standard permit are shown in Table 1-7.

Table 1-7: TNRCC Air Quality Standard Permit for Electric Generating Units NO_x Limits

East Texas Region

Installation Date	***Annual Hours of Operation***	***NO_x Limits (lb/MW-hr)***	***NO_x Equivalent ppm level (1)***
Prior to January 1, 2005	>300 hours	0.47	9
Prior to January 1, 2005	<300 hours	1.65	33
After January 1, 2005	>300 hours	0.14	3
After January 1, 2005	<300 hours	0.47	9

West Texas Region

Annual Hours of Operation	***NO_x Limits (lb/MW-hr)***	***NO_x Equivalent ppm level (1)***
>300 hours	3.11	63
<300 HOURS	21.0	420

(1) Based on a representative 5 MW gas turbine with 11,300 Btu/kW-hr heat rate and 8000 hours of operation

The West Texas standards represent BACT and are intended to allow for the clean reciprocating engines to comply under the standard permit, as well as clean diesel engines operating as peaking units. The initial East Texas standards represent limits recognizing the ozone problems in East Texas and should allow for the authorization of fuel cells, microtubines, gas turbines with catalytic combustion systems or flue gas clean up, and very cleanest reciprocating engines using catalytic converters. In 2005, the permit provides for a reduction in the standards.

1.2.3.2 US Environmentally Constrained Areas

The requirement for the ultra-low emissions levels that CESI's catalytic combustion system can achieve is geography-specific and currently limited to "environmentally constrained areas". The environmentally constrained areas include states in the ozone transport region of the Northeast, Northeast States for Coordinated Air Use Management (NESCAUM), Mid-Atlantic Regional Air Management Association (MARAMA) and other counties that have been identified as serious, severe and extreme non-attainment for ozone. More specifically, the environmentally constrained regions include:

- State segregation in Ozone Transport Region – CT, DE, ME, MD, MA, NH, NJ, NY, PA, RI, VT, parts of VA and District of Columbia.
- State segregation in NESCAUM- CT, ME, MA, NH, NJ, RI, VT
- State Segregation in MARAMA – DE, District of Columbia, MD, NJ, NC, PA, VA
- County segregation with serious, severe or extreme non-attainment status – CA, IL, IN, TX, WI, GA, LA, AZ

1.2.3.3 Emission Control Options

The competitive options that exist for meeting emission limits will vary depending on the state or local emission requirements. In attainment areas with modest BACT requirements (over 25 ppmv), little may be required from new sources. In severe or extreme non-attainment areas—or regions with "aggressive" environmental regulations—ultra low NO_x emission levels may be required (below 9 ppmv). Table 1-8 illustrates this on a qualitative basis. Catalytic combustion clearly becomes a competitive consideration in circumstances requiring ultra-low NO_x levels. It may become competitive under baseline (9-25 ppmv) situations if it offers operational or cost advantages over DLN combustors (e.g., improved combustion stability) or if market incentives such as emissions trading provide a driver for "over complying" with emission limits.

Table 1-8: Qualitative Emission Limits and Options

Emission Limit	**Main Competitive Options**
"High" Emission Limits *(Over 25 ppmv)*	Conventional diffusion combustors Steam or water injection
Baseline Emission Limits *(9-25 ppmv)*	Dry Low NOx combustors (lean premix) Conventional diffusion combustors with SCR Catalytic combustion
Ultra-Low Emission Limits *(Under 9 ppmv)*	Conventional diffusion combustors with SCR Dry Low NOx combustors with SCR Catalytic combustion

Table 1-9 lists a select number of gas turbine manufacturers with a brief overview of their company and their estimated lowest emission level capability (and whether they have some type of DLN combustor technology). The majority of gas turbine manufacturers are believed to have a DLN capability of some type for most or all of their turbine products. This equipment is likely to produce NO_x levels in the 9-25 ppmv range on natural gas. DLN combustors for liquid fuel, if even available, will have higher emission levels.

Table 1-9: Select Gas Turbine Manufacturers

Company	Estimated Emission Level DLN Combustors?	Overview
Alstom Power • Alstom Gas Turbines Ltd. • ABB's gas turbine line	 9-25 ppmv, yes 9-25 ppmv, yes	Recently formed company, merging the power generation businesses of ABB and Alstom. Mfrs 1.6-265 MW GTs. Also packages GE aero GTs.
AlliedSignal Engines (Honeywell)	9-25 ppmv yes	The new Honeywell company was created by the December 1999 merger of AlliedSignal Inc. (AS) and Honeywell Inc. In mid-1999 AS formed a joint venture with MTU (part of DaimlerChrysler) called Vericor Power Systems – to market AS's aeroderivative GTs. Merger with GE called off.
Dresser-Rand	15-25 ppmv yes	Former joint venture between Dresser (Halliburton) and Ingersoll-Rand. Recently acquired 100% by Ingersoll-Rand. Packager of GE aero GTs. Also manufactures two of its own light industrial GTs (1.4 & 1.8 MW).
Ebara	See P&W Canada and Turbo Power & Marine	Packaging partner of P&W Canada and Turbo Power & Marine (all aero GTs)
Eurodyne Gas Turbine	<25 ppmv yes	Joint venture of Ulstein Turbine AS (Norway), Turbomeca (France), and Volvo Aero Turbines (Sweden). Developed new 2.5 MW GT.
General Electric • Heavy duty • Aeroderivative	 9-25 ppmv, yes 15-25 ppmv, yes	Market leader in stationary power generation. Owns Nuovo Pignone and S&S Energy Products (the former gas turbine packaging division of Stewart & Stevenson).
Hitachi	9-25 ppmv yes	Major Japanese engineering and electronics company. Manufacturing associate for GE's heavy-duty GTs. Also manufactures two heavy-duty GTs of its own design (14 and 27 MW).
Kawasaki Heavy Industries	25 ppmv yes	Major manufacturer of 0.5-7.0 MW light industrial GTs for continuous duty & down to 200 kW for peaking.
Mitsui Engineering & Shipbuilding	25 ppmv yes	Major Japanese heavy industries company. Manufactures its own line of 1-23 MW light industrial GTs. Also a packager of Solar Turbines' light industrial GTs since about 1996.
Mitsubishi Heavy Industries	9-25 ppmv yes	Development partner of Westinghouse and Fiat Avio for heavy-duty GTs, and manufacturer of same. Also manufactures 3 light industrial GTs of its own design (6-30 MW) and packages Turbo Power's FT8 aero GT.
MTU Motoren- und Turbinen-Union Friedrichshafen GmbH	See AlliedSignal Engines and GE aeroderivative GTs	Partner in Vericor Power Systems joint venture with AlliedSignal Engines. Also a packager of GE aero GTs.
Niigata Engineering Co.	<25 ppmv yes	Packager of Solar Turbines' light industrial turbines. Also manufactures a line of 200-1,200 kW GTs for peaking service.
Nuovo Pignone	25 ppmv yes	Subsidiary of GE since 1993. Manufactures 2-10 MW light-industrial GTs and also packages GE aero GTs and builds GE heavy-duty GTs.

Company	Estimated Emission Level DLN Combustors?	Overview
OPRA Optimal Radial Turbine	9 ppmv yes	Dutch company (founded in 1995), manufacturing a 1.6 MW GT. Also developing a recuperated, higher-efficiency version.
Pratt & Whitney Canada	18-42 ppmv on 500-1,200 kW units, no (requires water injection) <10 ppmv on 2.0 - 4.0 MW units, yes	Subsidiary of United Technologies Corp. that manufactures small aircraft engines and their industrial aeroderivatives.
Rolls-Royce (including Allison)	<25 ppmv yes	Acquired Allison in 1995 and U.S. Turbine Corp. (now called Rolls-Royce Energy Systems) in 1996, and Vickers plc (including the former Ulstein Group of companies) in 1999.
Schelde Heron B.V. (established in 1996 as a result of cooperation between Heron Exergy and Royal Schelde)	<10 ppmv yes	Current owners/developers of the 43% elec. Efficiency 1.4 MW Heron GT – an intercooled, recuperated GT under development in the Netherlands since the mid-1980s. Commercial availability projected in 2002.
Siemens • Siemens • Siemens Westinghouse	 9-25 ppmv, yes 9-25 ppmv, yes	Siemens acquired the power generation business of Westinghouse in 1998. The heavy-duty GT lines of both companies continue to be produced and developed.
Solar Turbines	25 ppmv yes	Subsidiary of Caterpillar, Inc. and world's leading manufacturer of 1.2-12.8 MW light industrial GTs. Recently developed Mercury 50 (4 MW) recuperated gas turbine.
Turbomeca	25 ppmv ?	French manufacturer of 100-1,200 kW GTs for peaking and continuous duty.
Turbo Power & Marine	25 ppmv, yes	Subsidiary of United Technologies Corp. Manufactures the 25.5 MW FT8 industrial aeroderivative of Pratt & Whitney's large aircraft engine.
Yanmar Diesel Engine Co., Ltd.	?	Major Japanese manufacturer of diesel engines. Its line of 250-2,300 kW GTs is mainly for standby service.
Microturbines		
Capstone	Est. 9-25 ppmv Yes	Produces a 25-30 kW recuperated microturbine. Developing larger-scale 60 kW unit.
Elliott Energy Systems	<25 ppmv yes	Designing simple-cycle and recuperated microturbines ranging from 45-250 kW. In alliance with GE Power Systems for global distribution and service.
Honeywell (AlliedSignal)	Est. 9-25 ppmv	Introduceda 75 kW recuperated microturbine. GE has terminated plans to acquire Honeywell. Honeywell Power Systems Division is up for sale.
Ingersoll-Rand Energy Systems	9-15 ppmv Yes	Developing recuperated microturbine generator and air compressor products. Initial unit is 70 kW.

1.3 Emission Control Technology

The use of stationary gas turbines for power generation has been growing rapidly, a trend predicted to continue well into the future. In a competitive market, it could be more cost-effective to install small distributed generation units within the grid rather than constructing large power plants in remote locations requiring expansion of the transmission and distribution system. Beyond the issue of cost, public opposition to visible signs of industrial activity manifests itself in community resistance to distribution lines and large power plants. Small, onsite generation can be permitted along with the building itself, the equipment is not visible externally, fuel is readily available, and the environmental impact is minimal in terms of air emissions. For the customer, onsite generation can provide added reliability as well as leverage in negotiating the cost of purchased power.

Gas turbine emission control technologies are continuing to evolve, with older technologies being gradually phased out as new technologies are developed and commercialized. It has been recognized that add-on emission control technologies are cost-prohibitive in small gas turbine sizes; nonetheless, such controls may be mandated by stringent regional air quality regulations in many parts of the country. In the approaching competitive power market, the opportunities for small gas turbine installations will grow, but the project economics will more than likely be negatively impacted by such mandates if they require exhaust treatment approaches.

One of the key issues addressed in virtually every gas turbine application is emissions, particularly NO_x emissions. Decades of R&D have significantly reduced gas turbine NO_x emissions from uncontrolled levels. The evolution of cost-effective, low emission gas turbine combustion systems includes diluent injection (water or steam) and lean premixed (LPM) approaches. LPM combustors, also referred to as dry low emissions (DLE) or dry low NO_x (DLN), can differ in hardware from manufacturer to manufacturer, but the principle is the same. LPM combustors reduce peak flame temperatures by mixing fuel and air before combustion and by keeping the fuel-to-air ratio as low (lean) as possible. This avoids hot spots – regions where the fuel/air mixture burns in near-stoichiometric proportions, creating high-temperature zones that produce high levels of NO_x. Avoidance of local hot spot conditions inhibits NO_x formation through thermal fixation of atmospheric nitrogen. LPM combustors are now offered on nearly, all new gas turbines and as retrofits for existing popular models.

Ratcheting emissions limitations are driving further improvements in low emission combustion technology. Gas turbine manufacturers are pursuing “ultra-lean” premix, which pushes the theoretical limits of LPM techniques without compromising efficiency improvements or turbine durability, which is affected by flame stability (undesirable vibrations and acoustics that tend to occur as the lean limit is approached). The primary benefit of low emission gas turbine combustors, both conventional and catalytic, is to minimize local combustion temperatures. This reduces thermal NO_x production and, by reducing combustion instability and acoustics, allows combustion to proceed well below the stability limit of diffusion flames.

1.3.1 Catalytic Combustion for Gas Turbines

In catalytic combustion, the presence of a catalyst allows the fuel-air ratio to be very lean throughout the combustion mixture, so that combustion occurs at local temperatures below those at which significant NO_x quantities are formed. Catalytic combustion is a flameless process, allowing fuel oxidation to occur at temperatures approximately 1800°F (1000°C) lower than those in conventional diffusion-flame combustors. Catalytic combustors are being developed to control NO_x emissions down to less than 3 ppm. Data indicate that catalytic combustion exhibits low vibration and acoustic noise, only one-tenth to one-hundredth the levels measured in the same turbine equipped with DLN combustors. Compared to non-catalytic, lean premixed combustion, catalytic combustion has the advantage of less severe flame stability problems (less vibration and noise at extremely lean chemical conditions). This means that leaner mixtures become practical to burn.

Gas turbine catalytic combustion technology is being pursued by developers of combustion systems and gas turbines and by government agencies, most notably the U.S. Department of Energy (DOE) and the California Energy Commission (CEC). Catalytic combustion at atmospheric pressure has a long history of development for industrial, commercial, and residential applications. The potential benefit for gas turbine catalytic combustors is to allow a gas turbine to achieve ultra-low NO_x (low single-digit ppm), stable combustion stability, and low acoustics without requiring high-cost exhaust clean-up methods.

Past efforts at developing catalytic combustors for gas turbines have achieved NO_x at low, single-digit ppm levels but have failed to produce combustion systems with acceptable operating lifetimes. This was typically due to high-temperature and cycling damage and to the brittle nature of the materials used for catalysts and catalyst support systems.

Currently, catalytic combustor developers, such as CESI, and gas turbine manufacturers are testing non-brittle metal catalytic and “partial catalytic” systems that are intended to overcome the problems of past efforts. These efforts have evolved to the point where practical application of catalytic combustion in gas turbine systems has become feasible. Catalytic combustors capable of achieving NO_x levels below 3 ppm are in full-scale demonstration and have recently entered commercial production.

For gas turbine manufacturers to offer catalytic combustion commercially, the engineering development costs of gas turbine modification must be acceptable in terms of the expected market size and purchaser action timetable. Despite lower emissions being mandated in California and other areas with severe air pollution, such levels are not required in many segments of the world market where small gas turbines are sold.

The methodology and results described in the following sections of this report are an attempt to capture and address the perspectives of key stakeholders in the commercialization of catalytic combustion.

1.4 Methodology

The approach used in the review of commercialization requirements consisted of targeted telephone interviews with what were identified to be a sample of key stakeholders in the development, commercialization and utilization of catalytic combustion systems for industrial gas turbines.

Companies contacted and interviewed included those that manufacture or package industrial size 1-10 MW) gas turbine systems, develop gas turbine based projects, supply emission control equipment, and various other stakeholders. Environmental regulatory agencies, permitting consultants and energy policy "influencers" were also contacted in the course of this task.

1.4.1 Interview Topics

Each telephone interview included a discussion of target markets and applications, minimum customer requirements, design and integration issues and maintenance issues. The principal topics of each tried to include the following within the constraints of the interviewees' time:

- **Company Background –** a brief description of the company's product offerings and role in the industrial gas turbine market
- **Target Market Segments and Applications –** identify the applications of the company's product line such as CHP, standby, prime or rental power. Identify primary market segments include health care, schools, commercial, industrial, etc.
- **Current Environmental/Air Quality Issues –** identify current emissions requirements, trends, and recent precedent setting projects/permits. Perception of the options available to customers, costs (capital and operating), ease of implementation, costs of offsets, and any other issues associated of each option.
- **Successful and Unsuccessful Product Strategies** – discuss experience with innovative and early-commercial emissions control technologies. Describe a successful experience and an unsuccessful one.
- **Technology Issues that Affected Integration of Technologies –** discuss experience with integrating technologies from a technical/design perspective. For example, footprint requirements, onsite handling and storage of ammonia, etc.
- **Barriers that Affect Commercial Use of Technologies –** discuss the obstacles of integrating technologies into one's product offering. For example, cost to reconfigure current products, air emission permitting, installation costs, operating costs, durability, etc.
- **Awareness and Perception of Combustion Technology Options –** discuss the primary differences between combustion (pollution prevention) and exhaust treatment (pollution control) options. Perception of key players and the ability to deliver.
- **Reaction to CESI –** discuss Xonon specifications and perception of current state of product readiness, including results of ongoing Xonon RAMD performance characterization on a grid-connected gas turbine. (Note: The stakeholder interviews were conducted before the RAMD testing was completed. The demonstration of ultra-

low emissions and stable operation on the grid was part of the "product readiness" discussion, but the successful achievement of 8,000 hours of operation was not.)

- **Desired Characteristics of a Successful Technology/Partnership –** discuss the criteria for a successful and economically viable emission control system for industrial gas turbines.
- **Future Strategies –** discuss how companies are positioned to address the emissions issues in the small gas turbine market in light of their past experience and new technologies entering the market

1.4.2 Companies Interviewed

Representatives from the following organizations were contacted to participate in the survey effort. Their discussions are compiled later into this section of the report. Their descriptions should not be construed to represent the official views or policies of the company itself, but rather as a compilation of experience and opinions based on an individual's experience in the industry. Companies include:

- **Alliance Power**, Project developer of industrial sized gas turbine power plants. Alliance has an existing relationship with CES1.
- **Alstom (formerly ABB),** Manufacturer and packager of gas turbine systems. Family of GT's from industrial to large central station.
- **Alzeta,** Developer of low emission combustion technology.
- **Bay Area Air Quality Management District**
- **California Air Resources Board**
- **Cormetech,** Developer and provider of high (>800 F) and conventional temperature (400-800 F) SCR equipment.
- **Engelhard,** Catalyst provider. Developer of high temperature (>800 F) SCR.
- **Enron Energy Services,** Global conglomerate with roots in oil and gas business. It has diversified into all segments of the energy market and beyond to include broadband communications and online trading. Services include management of energy commodities, assets, information, facilities and capital, efficiency improvements and distributed generation.
- **GE/Nuovo Pignone/ Stewart & Stevenson,** Multinational corporation that develops, manufactures, packages, and finances GT power plants.
- **Goal Line Environmental Technologies,** Developer of zero ammonia exhaust treatment technology
- **Kawasaki,** Manufacturer and packager of gas turbine systems.
- **Onsite Energy Corp,** Energy services company (ESCO). Onsite was founded in 1982 primarily as a provider of cogeneration and other power generation/supply side services (inside the fence). In 1988, Onsite expanded to include demand side management services and now is a full-service ESCO with an emphasis on energy efficiency and

distributed generation, related consulting services, and direct access planning services for commercial and industrial customers.

- **Precision Combustion Inc.,** Developer of catalytic combustion technologies.
- **Resource Catalyst,** California-based air quality and permitting consultant.
- **Rolls Royce,** Multi-national firm that manufactures aircraft engines and aero-derivative engines among other products. Rolls Royce has acquired the Allison Engine Company in Indianapolis. They developed a business plan for a 50 kW and 250 kW micro-turbine, however, it has not been initiated.
- **Solar Turbines,** Developer, manufacturer, and packager of industrial size gas turbines.
- **South Coast Air Quality Management District**
- **Southern California Gas Company,** Natural gas distribution utility. SoCal Gas serves a territory of 23,000 square miles that ranges from central California to the Mexican border. SoCal Gas has an ambitious R&D program that actively collaborates with the energy industry, manufacturing partners, and government agencies to promote new technologies, improve existing technologies and streamline day-to-day operations.
- **Texas Natural Resources Conservation Commission**

Individuals have asked not to be identified by name.

1.5 Summary of Interviews

In the completion of this task it was clear that the level of understanding and familiarity with Xonon ranges from very familiar to limited knowledge of low emission combustion systems. The general sentiment from most interviewees was that there was some degree of uncertainty with regard to both the commercial readiness of Xonon and the emissions regulations that would require a product like Xonon.

It was nearly unanimous among interviewees that the potential growth for gas turbines in the 1-10 MW size range was large (the previous market status section verifies the growth in this segment), but that the realization of that potential will not be easy. Technology developments, such as Xonon, and a regulatory environment that gave small gas turbines an advantage over higher polluting reciprocating engines while simultaneously not imposing the requirement of SCR on this size class of equipment would go a long way toward realizing some of the already noted potential.

Gas turbine manufacturers made a point to recognize the benefits of pollution prevention approaches like Xonon in this size range over pollution control technologies such as SCR and SCONOx. However, the manufacturers made it clear that they were uncertain that a decision to commit to commercially offering a Xonon-based product at this time due to the perceived high development costs required and were examining multiple approaches. Durability and maintenance levels consistent with their current product offerings were cited as minimum requirements.

Project developers stressed the desire to not add additional technical risk to opportunities they were pursuing and had questions regarding what entity would provide warranties on performance and maintenance. Impacts on life-cycle costs in cycling and peaking applications were an issue identified.

The specific perspectives from stakeholders are examined in more detail in the sections that follow. Selected noteworthy comments and perspectives are listed below:

- Those in the gas turbine manufacturer and environmental regulatory communities had the relatively highest understanding of the development and commercialization status of Xonon. Both manufacturers and environmental regulators were aware of demonstration of Xonon at Silicon Valley Power and the positive results.
- Gas turbine manufacturers acknowledged existing development programs with Catalytica and identified issues such as development costs and an uncertain regulatory environment that does not provide a clear incentive to move forward with a Xonon based product at this time.
- Environmental regulatory agencies identified emission limit trends that are relevant to the need for products like Xonon for the DG market (e.g., SB 1298 in California and eastern Texas regulations and guidelines that will eventually put the same emissions limits on DG as there currently are on central station plants; NSR being reviewed; and emission limits that may favor CHP)
- Project developers, while familiar with low emission combustion approaches, had acknowledged very little experience with Xonon and were uncertain about its current commercial availability and performance guarantees.
- Project developers had also expressed some initial confusion about current emission requirements and the control technologies on which current limits are based.
- Project developers supported the development of any technology that would open markets that are currently “closed” to them due to strict emissions limitations.
- Project developers and gas turbine developers stressed strongly their aversion to risk and perceived uncertainties associated with Xonon (e.g., not certain of actual commercial rollout date, warranty issues, perceived high financial risk and the desire to limit technical risks.

1.6 Key Stakeholder Perspectives

The Commercial Requirements Task identified four key classes of stakeholders that will influence the commercialization of the Xonon combustion system. In some cases the groups are the combination of two or more stakeholder groups that going in to this task of the project were thought to have held some unique and distinct perspectives and issues. Based on the results of interviews and the emphasis on the DG (<10 MW market) we chose to group some (e.g., developers with end-users) whose concerns and issues were very much aligned. Those four stakeholder groups are:

- Developers and End-Users
- Gas Turbine Manufacturers (OEMs)
- Environmental Regulators (Air)
- Regulatory/Government/Energy Policy Bodies

The following sections present critical issues and concerns of the stakeholder groups at the time the interviews were conducted.

1.6.1 Developers and End-Users

Both project developers and the limited number of end-users interviewed shared similar attributes. The most significant issue was the perception of risk. The project developer sees project opportunities of this size to be somewhat limited (even though market data projections show this as a growing opportunity). His main concern is avoidance of factors that would endanger, delay, or increase the costs of a development opportunity. This posture has engendered a strategy of "fast-track" permitting with installation of large numbers of SCR units on recently sited non-utility generators. (For the most part these projects have been for a larger turbine size range than the one considered for this study.) This strategy is an example of the desire to make decisions that do not delay project scheduling, even if it requires increased capital costs.

In many cases, end-users, which elect to install gas turbine projects in this size range, consider themselves as project developers. They see themselves as more at risk than even the turnkey developer. In many cases they not only must consider the large initial capital investment and financing constraints, but also the impacts on their core business operations and the avoidance of disruptions to it.

Project developers and facility managers for end-users are aware of many cases in which technology developers "oversold" the operational readiness, and/or performance of their products.

Several key stakeholder attributes and perspectives are listed below:

- Fear risk
- Can't afford to "wait" for product
- Are uncomfortable with product and technology uncertainties – e.g., they aren't certain when Xonon will finally be ready and aren't sure what the operational warranties will be
- Feel they are taking substantial financial risk and seek to limit technology risk
- Have historically preferred larger projects as project development costs are approximately equal for small and large projects and payback to developer is larger for big project
- Recognize competition with reciprocating engines at low end of range.

- See near term market opportunity for capacity needs in certain regions (even outside California)

1.6.2 Original Equipment Manufacturers (OEMs)

In previous discussions with CESI staff, it is clear that they have developed a keen understanding of the issues and concerns that gas turbine manufacturers have. This task validated them for the most part. What was clearly evident was that the OEMs have closely tracked, monitored or participated in Xonon development projects and would prefer to have available a pollution prevention product like Xonon for this market segment, but point to several key issues as barriers.

From their relatively recent experience with low emissions combustion systems, many recognize the development costs associated with integrating Xonon with their individual models. One of the commercial objectives of recent DLN development programs was to establish low emission combustion as an economic alternative to SCR (i.e., the economic reduction of pollutants through pollution prevention without the threat of adding an expensive exhaust treatment system). This was particularly pertinent to gas turbines in the small size range where the costs of SCR could stifle the market. The perception is that the current emissions regulatory approach in this country still poses the real threat of requiring SCR in addition to DLN systems for even small gas turbines. The regulatory requirement of adding SCR regardless of emissions out of the gas turbine provides to many OEMs a disincentive to embark on an innovative, costly approach such as Xonon. Many feel that if innovative combustion systems are to be incorporated into commercial products, government funding will be required.

The need to validate performance, reliability, and durability in-house was highlighted by nearly all OEMs interviewed. The consensus among OEMs is that, if they are to guarantee performance of the combustion system, a robust testing, development, and engineering effort is required for any critical component. They expressed uneasiness about an outside supplier such as CESI owning and providing a critical component of their products. While recognizing the current advantage CESI has in terms of where it is in the development process relative to competing combustion technology development companies, several are evaluating other innovative combustion approaches through government subsidized R&D programs.

Several key stakeholder attributes and perspectives are listed below:

- Desire internal ownership of technology
- Perceive the current emissions regulations environment as unfavorable
- Prefer the availability of pollution prevention approaches over exhaust clean up
- Active in innovative combustion development efforts with DOE and other outside funding sources
- Emphasize catalyst life and durability as issues
- Recognize the engineering difficulties of integrating Xonon in specific models (e.g., external/can approach as being easier first application and perceive difficulties in annular combustor)

- Question the incentive to invest if emissions regulations will require exhaust cleanup regardless of turbine emission levels
- Possess uneasiness in reliance on an outside supplier playing a key role in a critical component of their machines (some would like to see other providers of catalytic combustors if they ever do become commercialized fully)
- Active in evaluating other approaches besides Xonon
- Seek to reduce risk by leveraging external funding (DOE, CEC, others) to test, demonstrate, and develop
- Unable to make a firm commitment to commercialize at this point

1.6.3 Environmental Regulators

Along with the OEMs, the air regulators possessed the most knowledge of Xonon and competing emissions control technologies. They all had been aware of the long-term testing at Silicon Valley Power. Interviewees from both CARB and TRNCC had recently reviewed the demonstrated Xonon performance given the developments with SB 1298 and the Texas Standard Permit summarized above. Interviewees had commented that for several years DG proponents have been pointing out the perceived uneven playing field that fossil fuel-based DG has with regard to both new central station plants and preferred renewable-based DG in the permitting process. They profess having open minds with regard to BACT determinations. However, they identify recently demonstrated ultra-low emissions levels from both SCONOx and Xonon on smaller sized gas turbines (<20 MW) as evidence that SCR-like levels can be achieved. Interviewees commented that manufacturers and those applying for permits have stated that Xonon is not commercially available.

Recent trends in both California and Texas reflect a movement toward output-based limits and standards (e.g., lb/MW-hr). This is intended to recognize and give credit to both the cleanest and most efficient generating units. Although the debate on the appropriate total efficiency requirements to qualify for CHP levels is still not resolved, they have expressed an interest in crediting the high efficiency of CHP applications. Both California SB 1298 and the Texas Standard Permit were developed in response to the DG community requesting both a streamlined permitting process and have some degree of certainty in limitations for the foreseeable future.

The regulatory community still uses as a baseline emissions from the cleanest and most efficient combined cycle central station plant for standards and guideline development. They feel strongly that DG should not be dirtier than new combined cycle plants, yet fail to take account of the additional electricity that is required with remote central station plants due to transmission and distribution line losses. In many cases this policy results in emissions specifications that are not technically achievable with the current state-of-the-art commercial technology. This is evidenced in the newly adopted SB 1298 and the original limitations in the Texas Standard Permit. There is a preference to facilitate the utilization of renewable technology and prevent emissions limits that result in a proliferation of diesel fueled engines.

Several key stakeholder attributes and issues are listed below:

- Consider themselves as forcing technology, not prescribing it
- Desire emissions controls technologies to be proven in practice
- Track extensively development efforts and demonstrations
- Project DG emissions becoming an issue, as they typically weren't closely regulated and don't want "diesels finding a backdoor"
- Have advocated regulations favorable to "clean" technologies
- Support rapid permitting of DG but don't want it any dirtier than typical new plant (i.e., new combined cycle)
- Recognize the value of CHP with its high total efficiency and fuel utilization
- Initiating CHP outreach programs to facilitate CHP (e.g., US EPA)
- Monitoring EPA review of New Source Review (NSR) rules --- impact on CHP at an existing site still not clear

1.6.4 Regulatory and Government

At the time of these interviews, energy policy was on the forefront of not only those agencies with energy policy jurisdiction, but at the highest levels of state and federal government. Unprecedented high electricity prices, high fuel costs, and scheduled rolling blackouts were simultaneously occurring. It was generally recognized that high efficient applications like CHP should be a prominent component of statewide and national energy policy. Given the current debate on the merits of increased energy supply versus energy efficiency and conservation, CHP provides benefits to proponents of both sides.

Federal and state supported R&D programs for DG, distributed energy resources, and CHP have seen a significant increase in both funding and public visibility. Federal and state R&D funding has supported gas turbine combustion programs specifically targeted at DG sized applications.

A coordinated effort between proponents of DG and CHP within government energy agencies and the environmental regulatory community is needed to ensure that the projects are implemented, the projected market is developed and subsequent benefits are achieved.

Key stakeholder perspectives and issues are listed below:

- Making energy policy a state and national priority
- Consider greenhouse gas emission limits a high priority but political issue
- Feel strongly that CHP and other high efficiency measures should play an important role in energy policy
- Have subsidized clean technologies (e.g., renewables, fuel cells) in both R&D and support of commercial demonstrations
- Considering if CHP should get the same treatment as the referenced clean technologies
- Have been lobbied by the CHP community for changes to tax laws and rate issues (primarily utility standby rates)

1.7 Near-Term Recommendations for Addressing Commercialization issues

Given the current size and projected growth rate of the industrial sized gas turbine market, a significant amount of value in terms of both public sector benefits and economic value to private industry is possible. However, ultimately evaluating the attractiveness of this market requires an objective assessment of market barriers and the ability of providers to enter the market and compete successfully.

Given the current market conditions and insights gained in the interview process, a near-term strategy that all stakeholders can support and still allow CESI to rapidly progress toward successful commercialization would be ideal. Energy Nexus Group recommends pursuing a near-term commercialization strategy focusing on gas turbine-based CHP applications.

A strategy based on CHP has several noteworthy advantages from the technical, application, and policy perspectives. From a technical and product positioning perspective, the electrical heat rates of gas turbines in the 1-10 MW size range face notable competition from reciprocating engines. However, gas turbines in this size range possess compelling advantages over reciprocating engines in both emissions (even more so with Xonon) and the quality of recoverable waste heat. With regard to technical risk related to Xonon itself, the OEMs have identified real and perceived risks with regard to development costs, design and integration into specific gas turbine models, and an uncertain regulatory climate creating dynamic emission requirements. These contribute to the need for continued support of Xonon from state and federal R&D to assist OEMs, as ultra-low emission combustion technology may be delayed without that support.

From an application perspective, CHP has a track record of successful implementation across a broad range of customer classes (e.g., industrial, institutional, and commercial) and has produced well-documented efficiency, emissions, and economic benefits. Project developers are familiar with the process of identifying and cultivating CHP opportunities. Studies supported by the California Energy Commission, DOE’s Energy Information Administration, and others have projected that a sizable untapped CHP potential still exists to entice the interests of money agents in the energy industry.

From a policy perspective CHP contributes to both the need for increased energy supply and additional energy efficiency measures. CHP represents one of the highest fuel utilization efficiencies possible, provides relief to constrained electric power delivery systems, and contributes to improved reliability of electric service in the event of a power outage. More importantly, CHP represents an application that all the key stakeholders can support. If CESI can appropriately position Xonon as a critical component that allows for the most economic application of CHP while still ensuring environmentally responsible siting, they stand a high probability in obtaining the support of stakeholders in the form of both R&D funding support and advocacy.

Energy Nexus Group outlines the following possible approaches in working in partnership with the key stakeholders to help ensure support for the commercialization of Xonon.

1.7.1 Project Developers/End-users:

- Develop consensus that CHP applications offer the best opportunity for gas turbines in this size range given the positioning with competing DG options (low simple cycle efficiencies and heat recovery possibilities)
- Work with multiple developers (avoid exclusive arrangements)
- Work with large ESCO's and unregulated utility affiliates (utilities still have strong resistance to baseload CHP)
- Look at current market activity (institutional and university/school markets seem ripe) and work with multiple developers to cultivate those markets (e.g., create standard "CHP package for certain sectors)
- Help to standardize sales and permitting approach to limit transactional and project development costs

1.7.2 OEMs

- Work with OEMs to secure external development funding as currently perceived high development costs make for a difficult internal sale when seeking internal funding
- Identify GT OEMs who are looking to take market share from leading companies; these OEMs may see that the upside potential justifies the development costs
- Clearly identify criteria for moving along the development path to commitment to commercialize and eventual full product rollout
- Jointly develop development programs consistent with that criteria

1.7.3 Environmental Regulators

- Make certain they are current with recent developments and pending milestones
- Track emissions regulatory actions in environmentally constrained geographical areas
- Show advantages of Xonon equipped gas turbines over other fossil fueled DG options (e.g., diesel gensets)
- Advocate determining output-based emissions limits that recognize the total high efficiency of CHP and give appropriate credit for heat recovery
- Advocate Xonon as a critical component that allows for the most economic application of CHP while still ensuring environmentally responsible siting
- Work with environmental regulatory community in outreach programs that communicate benefits of CHP
- Push for new rapid permitting procedures of CHP projects

1.7.4 Regulatory/Government

- In the development of state and national energy policies, take steps to ensure that CHP is a primary component of the strategy given its inherent high fuel utilization efficiency
- Look to get CHP considered a "clean" preferable technology along with renewables and fuel cells.

- Work with or join CHP advocacy groups (USCHPA) that support revised tax treatment, government R&D, real open access, and other policies to help further develop the CHP market
- Inform that given the technical and market risks associated with Xonon, continued government R&D support is required

2. QUANTIFICATION OF CRITICAL PUBLIC AND PRIVATE SECTOR BENEFITS TO THE STATE OF CALIFORNIA

2.1 Introduction

Catalytica Energy Systems, Inc. (CESI) was awarded by California Energy Commission (CEC) a project addressing the reliability, availability, maintainability, and durability of catalytic combustion systems for gas turbines. Catalytic combustion addresses the objective of reducing pollutant emissions from gas turbine generator sets burning clean natural gas. It falls under the CEC PIER identified subject area of Environmentally Preferred Advanced Generation (EPAG).

As part of the project team, Energy Nexus Group, a subsidiary of Onsite Energy Corp. identified critical commercialization issues, quantified key public and customer benefits, and provided recommendations for demonstration planning and market entry strategies. This report is the second of three topical reports covering the contracted scope of work. The three reports are identified below:

1. Review of Commercialization Requirements
2. Quantification of Critical Public and Private Sector Benefits to the State of California
3. Extrapolation of Benefits Beyond California and Recommendations for Initial Target Markets

The report is organized into the following sections:

- **Review of Distributed Generation Market Forecasts –** provides the market basis for evaluation of benefits
- **Technology Cost and Performance –** shows the primary technology options for achieving ultra-low emissions with gas turbines and the cost and performance benefits of the Xonon^{TM} technology.
- **Market Impacts –** shows the impact of Xonon technology on expected future market penetration of distributed generation in California.
- **Economic, Energy and Environmental Benefits –** quantifies the energy, economic, and environmental benefits of the Xonon technology to the California market.
- **Conclusions –** provides the final summary of key results.

2.2 Review of Distributed Generation Market Forecasts

Two recent studies addressing the likely future penetration of distributed generation (DG) technologies into the California market were used as the starting point for this evaluation of market benefits.[1,2] The first study, undertaken for the California Energy Commission by the authors of the present study, addresses the likely future market and benefits for combined heat and power (CHP) systems in California. The second study, undertaken for the California Air Resources Board and the California Environmental Protection Agency addresses the potential air pollution impacts of future market penetration of DG systems in the state.

2.2.1 CEC Forecast of CHP Markets

The CEC study provided a detailed assessment of CHP market potential and future market penetration in California. The study provided these key conclusions:

- There are currently 668 operating CHP sites in California with a generating capacity of 6,457 MW. A large share of this capacity is in sites larger than 40 MW. However, there are 2,068 MW of CHP located at 613 sites with less than 40 MW at each site.
- During the early to mid 1990s, CHP capacity was being added in California at the rate of over 400 MW per year.
- About 85% of total CHP capacity is natural gas fired.
- There are an estimated 28,000 remaining commercial and industrial sites in California that have thermal and electric load characteristics that would make them good potential candidates for installing CHP. These sites comprise 12,108 MW of potential additional generating capacity from CHP.
- Over the forecast period, it was estimated that under business-as-usual assumptions, an additional 4,009 MW of CHP capacity would penetrate the market over the forecast period (2000-2017.)
- With an aggressive program of CHP technology improvement, streamlined project implementation, financial incentives, and higher marketing effort by developers and energy service providers, it was estimated that future cumulative market penetration of CHP in California could provide an additional 8,900 MW at nearly 5,500 sites throughout the state.

Table 2.1 shows the cumulative market penetrations for CHP in California during the forecast period (2000-2017.) In the base case forecast, the future CHP penetration was expected to continue at a declining level over time, based on the average penetration rates experienced during the 1991-1996 period. Over 90% of this penetration was expected to be in the largest industrial size category of 20 MW and above, resulting in a market saturation of 59% of the remaining potential in this size range. In the base forecast, penetration of smaller packaged

[1] *Market Assessment of Combined Heat and Power in the State of California*, California Energy Commission, Onsite Energy Corporation, September 2, 1999.
[2] Joseph Iannucci, *et al*., *Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California*, California Air Resources Board and the California Environmental Protection Agency, Distributed Utility Associates, June 2000.

cogeneration systems less than one megawatt was shown to continue to be an extremely small percentage of total unrealized potential – less than 1% of total potential sites.

Table 2.1: High Case Cumulative Additions in Capacity and Projects and Percent Saturation of Total Remaining Available Market

CHP Category by Size	Cumulative Penetration in MW	Cumulative Penetration in Units	% of Total Market Penetrated
Base Case			
50-250 KW	0.8	8	0.03%
250-1000 kW	7.7	14	0.25%
1-5 MW	32.7	14	1.01%
5-20 MW	243.5	27	10.92%
> 20 MW	3724.7	45	59.12%
Total	4009.4	108	22.28%
Better Package Cost and Performance (Step 1)			
50-250 KW	2.6	26	0.08%
250-1000 kW	11.0	20	0.35%
1-5 MW	46.7	19	1.44%
5-20 MW	393.6	44	17.65%
> 20 MW	4122.1	50	65.43%
Total	4575.9	159	25.43%
Better CHP Package and CHP Initiatives (Step 1-2)			
50-250 KW	13.0	130	0.41%
250-1000 kW	15.9	29	0.51%
1-5 MW	67.7	28	2.09%
5-20 MW	542.7	61	24.34%
> 20 MW	5503.9	66	87.36%
Total	6143.1	314	34.14%
High Market Effort Scenario Total (Step 1,2,3)			
50-250 KW	389.9	3904	12.46%
250-1000 kW	568.9	1031	18.36%
1-5 MW	793.7	331	24.54%
5-20 MW	1319.7	148	59.18%
> 20 MW	5816.5	75	92.33%
Total	8888.7	5490	49.40%

The CEC study also examined factors that would increase penetration of CHP including advanced technology, passage of regulatory incentives for CHP, and enhanced marketing effort. The results of this analysis show that improvement to CHP package cost and performance, all else being equal, would raise cumulative CHP penetration over the forecast period from 4000 to 4575 MW – an increase of 14%. Adding the impacts of the various CHP initiatives to the improved technology would increase cumulative market penetration to 6143 MW – a total improvement compared to the base case of 53%. Finally, adding in the impacts of increased marketing effort and higher customer response rates provides for a cumulative CHP market penetration of 8,889 MW – a 122% increase compared to the base case.

In the high case scenario, market saturation for the smallest sizes of CHP would increase from less than 1% to 12-18%. This increase represents almost 5000 small systems with a combined capacity of nearly 1 megawatt. Improvements in the middle range systems of 1-20 MW is also substantial, growing from 277 MW of cumulative penetration in the Base Case to 2113 MW in the High Case. It is this middle range that is pertinent to the current analysis of the impacts of Xonon on market penetration. For this 1-20 MW size range, the forecast market penetration for CHP was 276 MW (41 units) in the base case and 2,113 MW (479) units in the high case.

The user benefits for these levels of penetration were defined in the report in terms of the *gross reduction* in power purchases. The correct definition of benefits is the net reduction in energy use and costs that result from replacing purchased power and fuel for boiler use with a CHP system. The calculation of these benefits is shown in **Table 2.2**. The results indicate that by the end of the forecast period, penetration of CHP in California could provide 347 trillion Btu/year in energy savings and close to a billion dollars in lower user energy costs. The unit savings shown in the table are declining due to the declining price track for purchased electricity that was assumed in the forecast.

Emissions benefits were calculated. Annual reductions in NOx emissions ranged from 1100 tons/year in the base case to 2,000 tons/year in the high case. Reduction in CO_2, a contributor to global warming was also significant in both cases due to the higher efficiency of CHP systems compared to separate purchase of electricity and generation of steam or hot water for thermal use.

Table 2.2: Comparison of Annual Energy and User Savings for the CEC Base and High Case Scenarios

Year	Base Case				High Case			
	CHP Generation GWh/year	Net Energy Saved 10^12 Btu	User Savings $Million/year	User Savings ¢/kWh	CHP Generation GWh/year	Net Energy Saved 10^12 Btu	User Savings $Million/year	User Savings ¢/kWh
2001	2,906	15	$88	3.02	2,906	17	$103	3.54
2002	4,803	25	$88	1.82	5,840	34	$136	2.34
2003	6,651	35	$118	1.77	8,783	51	$200	2.28
2004	8,460	45	$146	1.72	11,754	68	$262	2.23
2005	10,206	54	$168	1.65	14,729	85	$318	2.16
2006	11,911	63	$191	1.60	17,749	102	$375	2.11
2007	13,575	72	$211	1.56	20,823	119	$429	2.06
2008	15,191	80	$228	1.50	23,955	137	$480	2.00
2009	16,743	89	$239	1.43	27,140	155	$522	1.92
2010	18,268	97	$256	1.40	30,463	174	$574	1.89
2011	19,750	105	$267	1.35	33,928	194	$620	1.83
2012	21,200	112	$278	1.31	37,595	214	$670	1.78
2013	22,628	120	$292	1.29	41,543	236	$726	1.75
2014	24,026	127	$302	1.26	45,826	260	$779	1.70
2015	25,401	134	$312	1.23	50,551	286	$836	1.65
2016	26,757	142	$324	1.21	55,870	314	$901	1.61
2017	28,097	149	$335	1.19	61,949	347	$971	1.57

The 1999 CEC forecast was made before the natural gas and electricity price and supply disruptions of 2000. At the time, there was a very optimistic view of the impact that electric industry restructuring would have on future electricity prices in the state. According to the CEC electric price forecast used for the analysis, average retail commercial costs were expected to drop from 9.2 to 6.2 ¢/kWh and industrial costs were expected to drop from 6.7 to 4.8 ¢/kWh. This price drop was expected to occur fairly quickly after the end of the transition period with stability in real terms at the lower level over the course of the forecast period to 2017. The post-transition economic climate was expected to more closely resemble the situation that exists today in lower cost power states. The results of the last two years certainly call into question, this view of the future.

Secondly, the CHP technology characterizations used in the market analysis may not adequately reflect the levels of emission control that are being required for current permitting and may be required in the future due to initiatives such as SB 1298, *The Distributed Generation Certification Program.* Small reciprocating engine technology was allowed to compete at emissions levels reflecting rich-burn and three-way catalyst and larger engines were allowed to compete with lean-burn technology. DG sized turbine technology was controlled to 9 ppm using preliminary estimates of SCR cost and performance.

In Section 4, *Market Impacts*, we use the existing CEC market model to update the market results with new assumptions regarding electricity and gas prices and technology cost and performance – including the impacts of the Xonon™ technology.

2.2.2 CARB/C-EPA Assessment of DG Market Potential in California

The objective of this study was to determine the net air emissions effects from the potential use of cost-effective DG in California. The study looks at three distinct applications: (1) utility peak shaving, (2) utility baseload, and (3) customer applications. There was no attempt to define actual market penetration, but potentially economic markets for each DG technology were identified and the environmental impacts quantified. The draft study provided these conclusions:

- For utility support, DG was assumed to compete against new generation only. The value of DG was seen in the deferral of this capacity, therefore, the amount of capacity *in play* was defined on an annual basis. For 2002, 976 MW of potential new capacity was in play. For 2010, the potential new capacity was estimated at 1,144 MW.
- Using a proprietary utility cost model, the CARB report defines the shares of these markets that could be penetrated by individual DG technologies. These penetrations are neither presented in terms of an actual market forecast nor are they additive. Peak shaving applications are projected to be the most cost-effective utility application of DG. Individual technologies are competitive for 50-75% of the annual capacity additions projected for 2010.
- Baseload utility applications are much less competitive according to the CARB model. The most competitive technology, according to the analysis, is the advanced turbine system that would be economically competitive in 32% of new utility baseload capacity in 2002 and 42% in 2010.
- For both the peaking and baseload utility applications, only the advanced turbine system (ATS) was seen as capable of significantly reducing overall utility system NO_x emissions. Fuel cells, representing a near zero emissions technology, were not seen as having enough economic potential to provide a meaningful emissions reduction. All other DG technologies, according to the analysis, would increase overall utility emissions.
- For customer based DG, the target potential was identified as 11.7 GW. (This is very similar to the 12.1 GW identified above in the 1999 CEC study.) Microturbine and ATS based CHP systems were identified as competitive in this market. For 2010, 66.2% of the technical potential could be economically penetrated by the ATS in CHP mode. For microturbines with CHP, this economic share was 38.4%. In both cases, the application of CHP using these technologies was seen as providing a lower level of NO_x emissions for the state.
- The NO_x emissions results were based on microturbine and conventional turbine emissions of 25 ppm and ATS emissions of 5 ppm in 2002 and 2.5 ppm in 2010. These technologies competed against the average California utility generation mix having a NO_x emission rate of 0.13 lb/MW-hr --- an emissions rate comparable to a 32% efficient gas turbine at 3.3 ppm.

The emissions from an average California utility system are shown in **Table 2.3**. The economic potential shares and emissions impacts by technology are shown in **Table 2.4**. It is important to note that the emissions values in the table are for the utility system plus the DG emissions. Where DG penetration is assumed to be zero, the emissions are identical to *system only* emissions

Table 2.3: California Average Central Generation Emissions, lb/kW-hr

	NO_x	SO_2	CO	CO_2	PM	VOC
Pounds per kWh*	.00013#	.00002	.00017+	.20149	.00002	.00011

Source: CARB Study citing California Energy Commission
Equivalent to 3.3 ppm for a 32% efficient gas turbine
+ As reported in the source – based on calculations in the rest of the report, the value should be .0017.

Table 2.4: Central and Distributed Generation Economic Market Potential and Air Emissions, 2010

2010 Load Growth = 1,144 MW/yr	Portion of Growth (%)*	Tons of Emissions (Total System plus DG)					
		NO_x	SO_x	CO	CO_2	VOC	PM
Peaking Option							
System Only	100.0	15.5	2.4	239	24,032	2.4	13.1
Microturbine	75.3	90.0	3.2	279	100,776	4.5	10.1
Adv. Turbine System (ATS)	70.3	13.1	2.4	280	83,606	3.1	9.4
Conventional Comb. Turbine	79.0	102.8	2.3	170	95,502	3.2	38.9
Dual Fuel Engine	52.0	305.1	7.1	1,847	71,075	30.9	26.5
Otto/Spark Engine	54.5	169.3	1.7	608	71,465	94.7	24.7
Diesel Engine	74.8	1,460	428.8	917	151,654	172	260
Baseload Option							
System Only	100.0	370.1	56.9	5,694	573,665	56.9	313.2
Microturbine	13.7	693.9	60.4	5,569	925,693	64.1	301.5
Adv. Turbine System (ATS)	42.0	335.6	57.6	6,287	332,726	67.8	260.7
Conventional Comb. Turbine	15.8	786.7	56.6	5,369	914,876	60.9	436.4
Dual Fuel Engine	0.0	370.1	56.9	5,694	573,665	56.9	313.2
PEM Fuel Cell	1.7	364.5	56.0	5,597	597,367	56.0	307.9
Phosphoric Acid Fuel Cell	0.0	370.1	56.9	5,694	573,665	56.9	313.2

Source: *Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California*, CARB, June 2000.

The CARB study was still in draft form at the time we reviewed it for this work. Comments about the methodology and results relate to the draft results that may be changed in the final version. We don't feel that the market methodology developed for this analysis was intended to be used as an actual market forecast, but rather as a series of *what if* cases that show the relative competitiveness of DG options and their potential environmental impact on the state. Most significant for this analysis, NO_x clean-up technologies such as SCR and Xonon were not explored for conventional turbine technology. Lowest achievable emission rates were only defined for the ATS. This approach provides an incorrect view of the potential emissions impacts from gas turbines in DG applications.

For this study, we intend to utilize the CARB study characterization of the California utility system emissions and the values for defining avoided boiler emissions in CHP applications. These values will be combined with the CEC CHP market study methodology and updated with new technology cost and performance characteristics that clearly delineate the SCR and Xonon costs and an updated view of future gas and electric prices that define the competitive environment.

2.3 Technology Cost and Performance

Emissions control on small turbines has advanced significantly in the last decade. Given the EPA and California strategies to set emissions levels that are *technology forcing*, the acceptable NO_x emission levels for certification of a turbine-based project in California and other non-attainment areas have been lowered during this same period at an even more rapid rate. Initiatives such as SB 1298 that seek to standardize and streamline the distributed generation certification are expected to create an extremely clean, output-based standard.

It is expected, therefore, that for turbine-based generation technologies to meet future certification requirements, they will ultimately need to reduce NO_x emissions to 2.5 to 3.5 ppm levels. In fact, SB 1298 will require emissions levels that are half of this level by 2007. For this analysis, we selected 2.5 ppm as the performance target for NO_x emissions. As we will show in this analysis, there are significant benefits at this level in the reduction of emissions from older central station plants and in avoiding customer boiler emissions for DG systems in CHP duty.

To meet this level, we compared dry low NO_x (DLN) combustion with selective catalytic reduction (SCR) of exhaust emissions and catalytic combustion using Catalytica's Xonon technology. For comparison purposes, we also show the costs of DLN alone, though it is doubtful that the emissions levels achievable currently in small turbines (15-25 ppm) would be acceptable in California. It should be noted that state-of-the-art DLN in utility-sized turbines is capable of emissions control in the 7-9 ppm range.

The analysis was based on three turbines with capacities covering the range of "small" gas turbines as follows:

- 1.5 MW
- 5 MW
- 10 MW

Table 2.5 summarizes the capital and operating cost impacts for these three systems with three environmental control alternatives: DLN, DLN plus SCR, and Xonon catalytic combustion. The table shows the basic costs for the turbines and the three environmental control technologies. In addition, hidden costs are also identified that act to increase the capital or operating costs of the systems:

Direct Costs

- Basic turbine package cost
- Installed cost of a CHP system, exclusive of environmental control costs
- Added capital costs for the environmental control package selected – DLN, SCR, or Xonon
- Added direct operating costs – labor, contract maintenance, catalysts, parts, materials, added taxes

Table 2.5: Comparison of Environmental Control Costs for Three Turbines

Cost Category	**DLN**	**DLN/SCR**	**Xonon**
1.5 MW			
Turbine Package Cost $/kW	$600	$600	$600
CHP Installed Cost exc. emissions control $/kW	$1,168	$1,168	$1,168
Emissions Control Cost Additions			
Direct Capital Cost Additions $/kW	$56	$268	$85
Direct Operating Cost Additions mills/kWh	2.8	12.3	4.1
Hidden Cost Additions			
Revenue Lost for Air Permit Delay $/kW	$123	$32	$0
Pressure Drop and Parasitic Power mills/kWh	0.0	1.0	0.0
Unscheduled Shutdown mills/kWh	0.7	0.8	0.4
Offset Cost mills/kWh	4.3	0.4	0.4
Total Emissions Control Costs			
Capital $/kW	$179	$300	$85
Operating Cost mills/kWh	7.8	14.6	4.9
5 MW			
Turbine Package Cost $/kW	$400	$400	$400
CHP Installed Cost exc. emissions control $/kW	$845	$845	$845
Emissions Control Cost Additions			
Direct Capital Cost Additions $/kW	$41	$141	$54
Direct Operating Cost Additions mills/kWh	1.0	4.9	3.1
Hidden Costs Additions			
Revenue Lost for Air Permit Delay $/kW	$138	$43	$0
Pressure Drop and Parasitic Power mills/kWh	0.0	0.9	0.0
Unscheduled Shutdown mills/kWh	0.7	0.8	0.4
Offset Cost mills/kWh	3.4	0.3	0.3
Total Emissions Control Costs			
Capital $/kW	$178	$185	$54
Operating Cost mills/kWh	5.2	7.0	3.8
10 MW			
Turbine Package Cost $/kW	$300	$300	$300
CHP Installed Cost exc. emissions control $/kW	$679	$679	$679
Emissions Cost Additions			
Direct Capital Cost Additions $/kW	$37	$109	$51
Direct Operating Cost Additions mills/kWh	0.7	3.1	3.0
Hidden Costs			
Revenue Lost for Air Permit Delay $/kW	$146	$48	$0
Pressure Drop and Parasitic Power mills/kWh	0.0	0.9	0.0
Unscheduled Shutdown mills/kWh	0.7	0.8	0.4
Offset Cost mills/kWh	3.2	0.3	0.3
Total Emissions Control Costs			
Capital $/kW	$184	$157	$51
Operating Cost mills/kWh	4.6	5.2	3.7

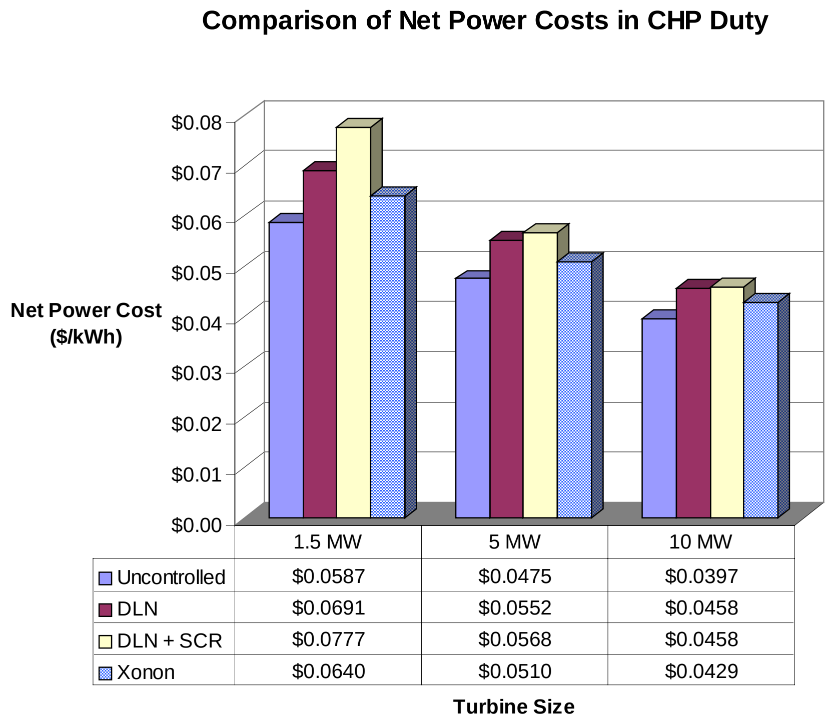
Hidden Costs

- Revenue Lost for Air Permit Delays – Permitting turbine systems in highly controlled areas such as California and the Northeast using DLN control technology only will become increasingly difficult if not impossible. There will be delays or denial of certification. For DLN plus SCR systems there will likely be delays related to demonstrating the safety of the ammonia handling system. For this comparison, we assumed 9 months was required to certify a DLN system[3], 5 months for DLN plus SCR system, and 3 months for a Xonon system.
- Pressure Drop and Parasitic Power – The SCR system adds to turbine back pressure and requires additional parasitic power consumption. These losses amount to about a 1.1% reduction in system capacity, and about 0.4% increase in fuel use per unit of output.
- Unscheduled Shutdown – DLN systems have had some history of failures due to vibration and flame instability. SCR systems based on DLN will have these same tendencies plus additional risk factors related to the SCR system. For this analysis, we assumed 36 hours of unscheduled downtime for the DLN system and 52 hours for the DLN/SCR system. It was assumed that the Xonon system would face fewer unscheduled shutdowns than the DLN or SCR system – only a quarter of one percent of operating hours or about 20 hours/year.
- Offset Cost – Systems in California and in some other markets must provide offsets for added emissions. It was assumed that these offsets would cost $6,000/ton. Both the SCR and Xonon systems are designed to control NO_x down to 2.5 ppm so they have the same offset cost. DLN at 25 ppm will have offset costs that are 10 times higher.

For each of the systems shown in the table, we calculated the net power cost from a CHP system. The net power cost is the fully amortized owning and operating costs on a per kWh basis after the avoided costs of a separately fueled boiler are subtracted from the operating costs. These systems are based on natural gas fuel costs of $4.50/MMBtu. **Figure 2.1** shows the comparison of costs for an uncontrolled system, DLN, DLN plus SCR, and Xonon. All of the hidden costs are incorporated into these cost estimates except for the uncontrolled case that is included for reference only – not as a realistic alternative for non-attainment areas.

Xonon technology can produce net power costs that are only 7-9% more costly than an uncontrolled turbine. In addition, Xonon achieves the same NOx emissions levels as the DLN plus SCR option at costs that are 7-21% lower.

[3] It is increasingly likely that in California, DLN systems will be unable to obtain permitting without also adding SCR.



	1.5 MW	5 MW	10 MW
Uncontrolled	$0.0587	$0.0475	$0.0397
DLN	$0.0691	$0.0552	$0.0458
DLN + SCR	$0.0777	$0.0568	$0.0458
Xonon	$0.0640	$0.0510	$0.0429

Figure 2.1: Comparison of Net Power Costs for CHP Systems as a Function of Emissions Control Technology

To put these unit numbers in perspective, an individual 5 MW CHP project meeting its emissions requirements with a Xonon control system can produce power with a net cost that is 10% cheaper than a system with DLN/SCR control. However, this 10% cost reduction produces a 70% increase in the annual savings when compared with an estimated average power cost of $0.065/kWh. **Figure 2.2** shows the comparison in annual user savings for the SCR/DLN and the Xonon systems. The 5 MW CHP customer using SCR could save $341,000 per year compared to purchased power and a separately fueled boiler, whereas a CHP customer using Xonon would save $582,000 per year.

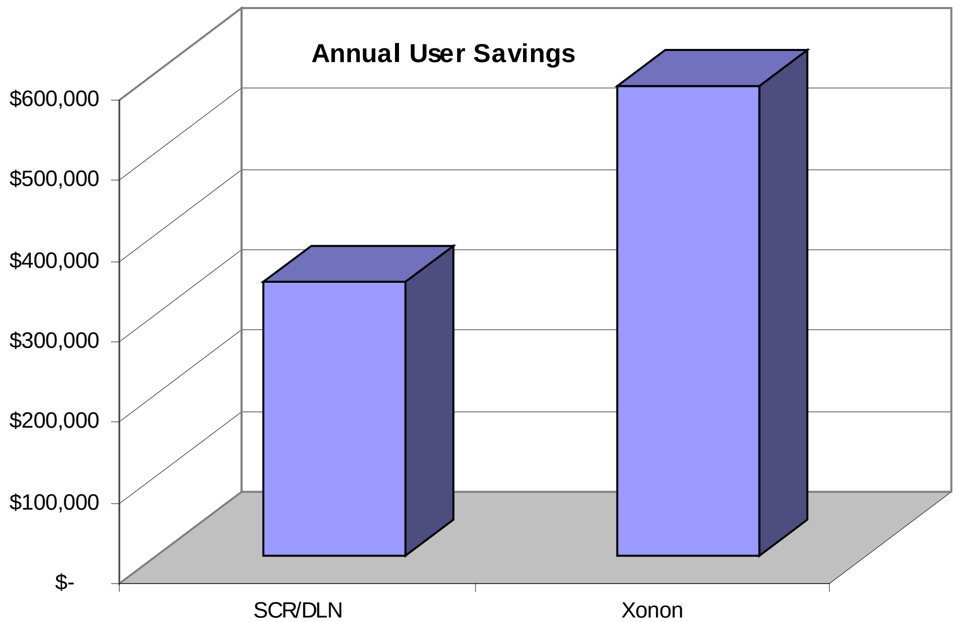


Figure 2.2: Comparison of Yearly Savings for 5 MW System: Purchased Fuel and Power Costs versus Fully Amortized CHP Owning and Operating Costs

As we will demonstrate in the next section, this benefit will not only accrue to every new CHP plant that goes on line using Xonon catalytic combustion, but the added savings will also make additional projects cost effective compared with other technology options like SCR. Therefore, the benefits of Xonon catalytic combustion include cost savings for each user and also higher market penetration of DG due to these additional savings.

2.4 Market Impacts

Starting with the CHP market model that we developed for CEC[4], we updated the fuel and power outlook to reflect recent changes and updated the technology cost and performance values using the data presented in *Section 3*. The net result from these changes is that Xonon equipped gas turbines can achieve an additional 855 MW of market penetration in California between now and 2017, compared to gas turbines using DLN plus SCR to achieve the same level of emissions reduction. These added systems represent an 18.5% increase in the CHP market for California.

2.4.1 Approach

The CEC CHP market assessment had the following components:

- Gas and electric price forecasts through 2017 (updated for this analysis)
- Cost and performance estimates for CHP systems in 5 sizes (modified here based on technology estimates developed in Section 3.)
- Prototype customer economic models in these size categories that combine the customer load characteristics, technology cost and performance, and future fuel and power prices to define year-by-year internal rate of return (IRR) estimates (unchanged.)
- Remaining technical market potential was determined using a detailed database analysis (unchanged.)
- Market penetration was based on the historical rate of market penetration in California during the 1991-1996 period. The market penetration forecast is based on the relationship between the project IRR during the historical period and the IRR figures calculated for each size bin and year. (Some modifications to the prior CEC approach were made to ensure that market penetration rates would not exceed the technical market potential.)

According to the CEC electric price forecast used for the 1999 analysis, average retail commercial costs were expected to drop from 9.2 to 6.2 ¢/kWh and industrial costs were expected to drop from 6.7 to 4.8 ¢/kWh. Given the price increases that have taken place since this forecast, we assumed that the real price of electricity would be 8.5 ¢/kWh in the commercial sector and 6.5 ¢/kWh in the industrial sector.

The gas price forecast used in the 1999 analysis showed commercial gas prices ranging from $2.80 to $3.40/MMBtu and industrial gas prices ranging from $2.30 to $3.00/MMBtu over the forecast period. For this analysis we assumed that commercial gas prices would stabilize at $5.50/MMBtu and industrial gas prices at $4.50/MMBtu.

The technology/customer performance models were rerun using the new price forecasts and the new technology specifications. The technology specifications were only changed in the sizes appropriate for gas turbines, i.e., 1-5 MW, 5-20 MW, and greater than 20 MW. In these sizes, the industrial power and fuel rates apply.

[4] *op cit*., Onsite Energy Corporation for the California Energy Commission, September 2, 1999.

In the 1-5 MW size range, the 1.5 MW Kawasaki turbine specifications were used to determine IRR and market share. In the 5-20 MW size range, the 5.2 MW Solar turbine was used. In the Larger than 20 MW site size range the cost and performance specifications for the 10 MW GE10 were used, though larger turbines would also compete in this size range.

2.4.2 New Market Penetration Rates

The cumulative market penetration estimates for the revised CEC market model are shown in **Table 2.6**. In the size range of interest between now and 2017, future cumulative market penetration of CHP based on gas turbines using DLN plus SCR equals 4,587 MW. Using Xonon, cumulative market penetration increases to 5,443 MW – a net increase of 856 MW. Market penetration of the 1.5 MW product for CHP applications is very low due to the higher cost and poor heat rate that lead to a lack of competitiveness with both purchased power and fuel options and also reciprocating engine based systems.

Table 2.6: Comparison of the Impacts of DLN/SCR and Xonon on CHP Market Penetration

CHP Size Category	Cumulative Penetration in MW		
	Market Penetration with DLN plus SCR	Market Penetration with Xonon	Added Market Penetration due to Xonon
1-5 MW	10	66	57
5-20 MW	522	757	235
> 20 MW	4,056	4,620	565
Total	4,587	5,443	856

2.5 Economic, Energy, and Environmental Benefits

This section quantifies the economic, energy, and environmental benefits associated with use of the Xonon catalytic combustion technology compared with the more costly DLN plus SCR. These benefits are based on the market model and data inputs described in the previous sections.

2.5.1 User Savings

As shown in Section 2.3, a CHP site can generate power more cheaply using the Xonon technology than with SCR. This cost reduction saves money for each site operating a CHP system using the technology. In addition, applications that are uneconomic or marginal with SCR may become economic using Xonon. The estimate of annual user and energy savings is shown in Figure 2.3. The figure shows the annual stream of user benefits from CHP systems using either DLN/SCR or Xonon for emissions control based on the market penetration estimates shown in the previous section. As market penetration increases, the cumulative number of operating CHP systems also increases providing users with reduced energy costs. By 2017, in the SCR case, users will save $709 million in meeting their energy needs. In the Xonon case, this figure increases to $977 million/year..

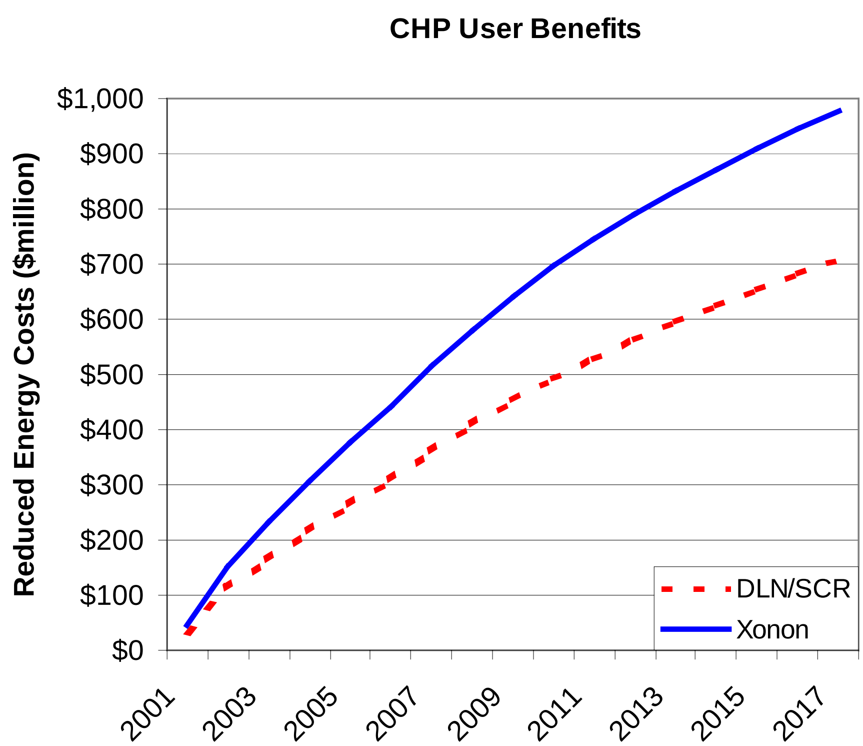


Figure 2.3: Comparison of Annual User Benefits for CHP Sites based on the SCR and Xonon Market Penetration Rates

The total sum of benefits (the area under the curve) is over $10 billion for the Xonon based market penetration case. This figure is nearly $3 billion greater than in the DLN/SCR penetration case. The net present value today, using a 10% discount rate, of the increased future stream of savings due to Xonon is over $1 billion. These savings correspond directly to increased productivity for California's commercial and industrial sectors – money that can go into newer processes, more equipment, more workers, etc., rather than into meeting energy bills.

2.5.2 Energy Savings

Figure 2.4 shows the annual stream of energy savings due to CHP in the two market scenarios. CHP systems use less energy than central station power plants and separate boilers because the exhaust heat is utilized productively in meeting onsite thermal needs rather than being wasted as it is in central power stations. Future market penetration will be greater using the less costly Xonon technology; therefore, the total market energy savings will be greater. The total energy savings from CHP using Xonon technology over the forecast period equal about 2 quads of energy. The differential energy savings due to Xonon are on the order of 0.3 quads.

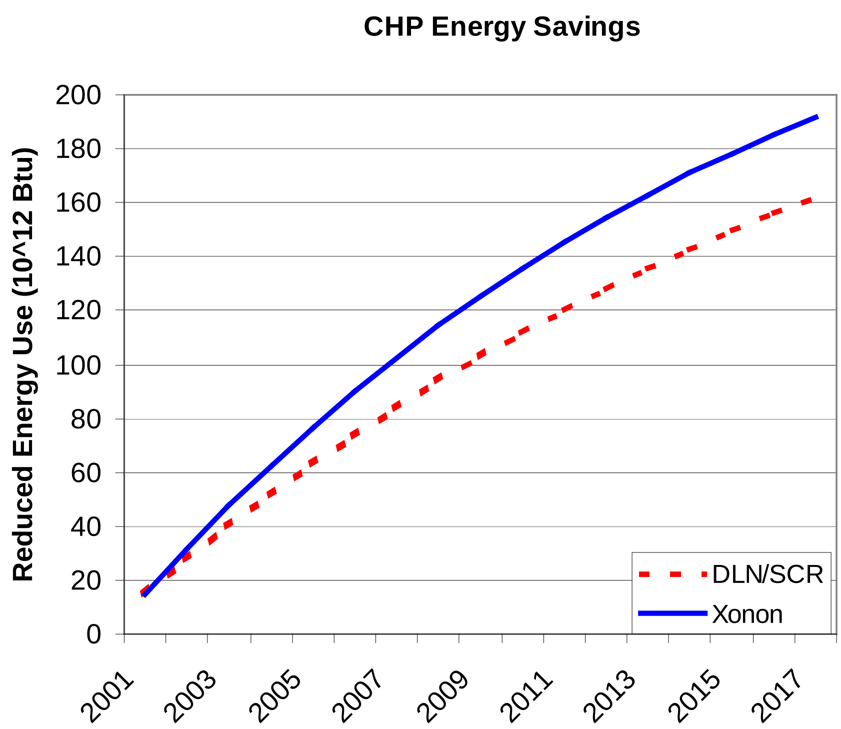


Figure 2.4: Comparison of Annual Energy Savings for CHP Sites based on the SCR and Xonon Market Penetration Rates

Apart from the user savings already quantified, energy savings represent a social benefit in lowering the pressure on fuel and electricity supply and infrastructure, thereby providing lower prices for all consumers. In addition, lowered energy use helps to reduce CO_2 emissions that contribute to global warming. These impacts are difficult to quantify, but represent at least part of the motivation behind social goals, evident in California, to increase the efficiency of energy utilization.

2.5.3 Environmental Benefits

The DLN/SCR and Xonon technologies compared for this analysis were set to provide the same level of NO_x emissions; therefore, one might expect that there is no change in environmental impact. However, the CHP systems, either with DLN/SCR or Xonon, provide an environmental benefit compared with the emissions produced by central station power plants and the on-site boiler emissions. To the extent that the Xonon technology encourages greater CHP market penetration, these environmental benefits are correspondingly increased.

We looked at two cases of environmental benefit. In the first case we used the values for average California central station emissions and boiler emissions from the CARB study described in Section 2.2. The average NO_x emissions from the California utility industry are 0.13 lb/MW-hr. The avoided boiler emissions, as defined in the CARB study, are 0.098 lb/MMBtu. In the second case, we used a NO_x emissions standard of 0.05 lb/MW-hr as a representative measure of the NO_x emissions from a state-of-the-art combined cycle power plant. (Note: A NO_x limit of 0.05 lb/MW-hr was initially proposed for 2007 in the SB 1298 regulation. The final approved value in SB 1298 was 0.07 lb/MW-hr, as shown in Table 1-5. The cost analysis discussed below was completed before SB 1298 was released in its final form.) For the avoided boiler emissions, we used 0.035 lbs/MMBtu representing low NO_x burners and flue gas recirculation.

The net change in NO_x emissions for each scenario is based on the following:

- CHP Generation = Cumulative CHP capacity additions X hours of use in each size class (approximately 7000)
- Avoided Utility Generation = CHP Generation X (1 + line loss %(6%)
- Avoided Boiler Fuel = CHP Generation X thermal energy per kWh / Boiler efficiency (80-85%).

Table 2.7 shows the NO_x emissions impacts of the two emissions control strategy market penetration scenarios using the CARB study values for avoided generation and boiler emissions described above. In this case, the emissions from the CHP systems are cleaner than the corresponding existing generation that is being avoided. In addition, the on-site CHP systems emit only one-sixth of the NO_x of the boiler systems that they are replacing. In this comparison, overall NO_x emissions reductions from CHP implementation are expected to reach 9,587 tons/year in the DLN/SCR market penetration scenario. The Xonon market penetration scenario reduces emissions by 11,443 tons/year – a net decrease of 1,855 tons/year.

Table 2.7: NOx Emission Reductions for the DLN/SCR and Xonon CHP Market Penetration Scenarios based on Backing out Existing Boiler and Generation Technology

CHP Category by Size	Cumulative Penetration in MW	CHP Emissions tpy	Boiler Emissions tpy	Utility Emissions tpy	Net Change tpy
SCR Case					
1-5 MW	10	4.4	29.4	4.4	-29.4
5-20 MW	522	191.7	1,091.6	237.9	-1,137.8
> 20 MW	4,056	1,396.0	7,969.3	1,847.4	-8,420.7
Total	4,587	1,592.2	9,090.3	2,089.7	-9,587.8
Xonon Case					
1-5 MW	66	30.5	201.5	30.2	-201.3
5-20 MW	757	277.9	1,581.8	344.7	-1,648.7
> 20 MW	4,620	1,590.4	9,078.9	2,104.6	-9,593.1
Total	5,443	1,898.7	10,862.2	2,479.5	-11,443.0

While it is logical to assume that CHP competition will tend to preferentially replace existing generation and boilers, it is perhaps more conservative to calculate the benefits of the two CHP market penetration scenarios based on the avoided emissions from new generation and boilers. **Table 2.8** shows this comparison. The CHP generation emissions remain the same, though these emissions are no longer lower than the avoided central station generation emissions from new sources. However, the CHP emissions are lower than the avoided boiler emissions, though not as dramatically as in the existing technology comparison used in the CARB analysis. The net decrease in NO_x emissions due to the use of Xonon compared to DLN/SCR, in this case is 476 tons/year.

The significant reductions in NO_x emissions due to the implementation of CHP point to an interesting side conclusion with respect to the SB 1298 2007 standard. Emissions from CHP systems based on gas turbines with NO_x emissions controlled to 2.5 ppm remain about twice as high as the new standard. However, the analysis shows that there are significant benefits from backing out boiler emissions. These benefits might remain unrealized if the current standard acts to discourage rather than encourage the implementation of a clean and energy efficient technology like CHP.

Table 2.8: NO_x Emission Reductions for the DLN/SCR and Xonon CHP Market Penetration Scenarios based on Backing out New Boiler and Generation Technology

CHP Category by Size	Cumulative Penetration in MW	CHP Emissions tpy	Boiler Emissions tpy	Utility Emissions tpy	Net Change tpy
SCR Case					
1-5 MW	10	4.4	10.5	1.7	-7.7
5-20 MW	522	191.7	389.7	91.5	-289.4
> 20 MW	4,056	1,396.0	2,845.0	710.5	-2,159.6
Total	4,587	1,592.2	3,245.2	803.7	-2,456.8
Xonon Case					
1-5 MW	66	30.5	71.9	11.6	-53.1
5-20 MW	757	277.9	564.7	132.6	-419.4
> 20 MW	4,620	1,590.4	3,241.1	809.5	-2,460.2
Total	5,443	1,898.7	3,877.8	953.7	-2,932.8

2.6 Conclusions

To achieve the increasingly strict limits on NO_x emissions in California, gas turbine distributed generation systems must utilize control technologies such as dry low NOx combustion plus selective catalytic reduction or Xonon catalytic combustion.

DLN is capable of reducing NO_x emissions to 25 ppm in the size range considered (1.5 to 10 MW). Direct costs range from $37 to $56/kW. SCR needs to be added to DLN system to bring emissions down to levels of 2.5 to 3 ppm. These systems are very costly in smaller systems costing $268/kW in the 1.5 MW size down to $109/kW in the 10 MW size range. Direct operating costs for DLN in the 10 MW size range add about 0.7 mills/kWh to O&M costs. The corresponding increase in O&M for SCR and Xonon is about 3 mills/kWh for each technology. In smaller sizes, the direct operating costs for SCR increase at a faster rate than Xonon.

These direct costs understate the true costs of DLN and SCR because there are hidden costs that add the cost of generation. These hidden costs include revenue lost for air permit delays for less effective or more complex control systems, pressure drop and additional parasitic power use (for SCR), increases in unscheduled shutdowns due to additional risk factors inherent in DLN and SCR systems, and higher emissions offset costs for systems that attempt to certify using DLN alone.

Based on a comparison of these costs and analysis of CHP applications between 1.5 and 10 MW, Xonon technology can produce net power costs that are only 7-9% more costly than an uncontrolled turbine. In addition, Xonon achieves the same NO_x emissions levels as the DLN plus SCR option at costs that are 7-21% lower. An individual 5 MW CHP project meeting its emissions requirements with a Xonon control system would have annual energy cost savings or $582,000 – over 70% higher than the corresponding savings using DLN plus SCR.

Using a CHP market analysis approach originally developed for CEC in a prior project, we calculated that Xonon equipped gas turbines can achieve an additional 855 MW of market penetration in California between 2001 and 2017, compared to gas turbines using DLN plus SCR to achieve the same level of emissions reduction. These added systems represent an 18.5% increase in the CHP market for California.

The total sum of user cost savings is over $10 billion for the Xonon based market penetration case. This figure is nearly $3 billion greater than in the DLN/SCR penetration case. The net present value today of the increased future stream of savings due to Xonon is over $1 billion. These savings correspond directly to increased productivity for California's commercial and industrial sectors. The total energy savings from CHP using Xonon technology over the forecast period equal about 2 quads of energy. The differential energy savings due to Xonon are on the order of 0.3 quads.

The market penetration scenario based on the use of Xonon technology reduces total NO_x emissions by 11,443 tpy compared to the existing mix of power generation and commercial and industrial boilers in California. Comparing emissions to new central station and boiler emission factors produces a less dramatic reduction (2,932 tpy) in total NOx emissions. The higher market penetration rates for Xonon based CHP systems compared to DLN/SCR systems results in lower emissions attributable to Xonon – even though the Xonon and DLN/SCR technologies have equivalent emissions levels at each site.

The Xonon technology will help the California economy by increasing the productivity of industrial and commercial facilities, encouraging stability of fuel and power markets by reducing demand pressure, and encouraging an accelerated reduction of air pollution in the state.

3. UNITED STATES MARKET FOR INDUSTRIAL-SIZED GAS TURBINES WITH CATALYTIC COMBUSTION SYSTEMS

3.1 Introduction

Catalytica Energy Systems, Inc. (CESI) requested for a scope of work from Onsite Energy to address commercialization issues as a sub-contractor in their response to California Energy Commission (CEC) RFP No. 500-97-503 as part of the Public Interest Energy Research Program (PIER).

Catalytica Energy Systems, Inc. (CESI) was awarded by California Energy Commission (CEC) a project addressing the reliability, availability, maintainability, and durability (RAMD) of catalytic combustion systems for gas turbines. Catalytic combustion addresses the objective of reducing pollutant emissions from gas turbine generator sets burning clean natural gas. It falls under the CEC PIER identified subject area of Environmentally Preferred Advanced Generation (EPAG).

As part of the project team, Energy Nexus Group, a subsidiary of Onsite Energy Corp. identified critical commercialization issues, quantified key public and customer benefits to the state of California, and provided recommendations for market entry strategies.

This report documents the results of Energy Nexus Group's efforts. Energy Nexus Group drew on its developed knowledge, expertise and experience in the development and commercialization advanced energy systems. The tasks described in this report provide a qualitative assessment of the US market for industrial sized gas turbine based systems with catalytic combustion. The Report identifies potential initial markets for commercialization.

This report is the last of three topical reports representing the three primary sections related directly to the three primary tasks of Energy Nexus Group's contracted scope of work:

- Review of Commercialization Requirements
- Quantification of Critical Public and Private Sector Benefits to the State of California
- Extrapolation of Benefits Beyond California and Recommendations for Initial Target Markets

The first two topical reports of this project identified Combined Heat and Power (CHP) as the best application for gas turbine systems in the 1-10 MW size range with catalytic combustion and provided a quantitative assessment of its benefits to the state of California.

3.2 Objectives

In the previous tasks of this project a quantitative analysis of the benefits to California from the commercialization of catalytic combustion was conducted. The market for power generation and distributed generation equipment extends well beyond the boundaries of California. It is the entire market that justifies investment in research and development and in production facilities. This topical report provides a qualitative assessment of the United States CHP market for gas turbines in the 1-10 MW size range. Furthermore, it identifies states with prevailing electric rates that could allow economic utilization of 1-10 MW gas turbine-based CHP projects with catalytic combustion, identifies states that have air emissions regulations that may require ultra-low emissions, and recommends customer sectors and states that could be attractive initial target markets.

3.3 Background

There has been remarkable growth in worldwide prime mover (combustion turbines and reciprocating engines) demand during the past decade. This is driven by several factors, including growth in developing nations and a demonstrable market shift away from conventional large-scale thermal power plants toward use of prime movers for power generation—especially larger (over 30 MW) gas turbines in simple- and combined-cycle configurations.

The application of gas turbines for stationary power generation has grown considerably over the past decade and is projected to continue to grow in the future. Strong gas turbine demand is based on several key product attributes associated with combustion turbines—high efficiency in combined-cycle configurations; low capital, operating, and maintenance costs; high reliability and availability; shortened lead time for permitting and construction; and low emissions.

While exhaust emissions from natural gas-fueled and distillate-fueled CTs are low, continued environmental pressure is resulting in permitted emission limits in some areas being below what is commonly achievable even with advanced dry low NO_x (DLN) combustors. An alternative combustion approach, catalytic combustion, offers the potential to achieve ultra-low NO_x emission levels without the complications and cost of post-combustion emission controls. The distinctive features of catalytic combustion relative to other technologies are described in Sections 1.3 and 1.3.1.

The first two tasks of this project identified combined heat and power (CHP) as the best distributed generation application for gas turbines in the 1-10 MW range. The results and recommendations described in the following sections of this report are an attempt to qualitatively assess the US market for industrial-sized gas turbine-based CHP systems using catalytic combustion. The report also identifies several potential initial target markets that would facilitate the successful commercialization of catalytic combustion.

3.4 Methodology

The technical approach used in this assessment and development of recommendations consisted of the following components:

1. Review a database (PA Consulting Hagler-Bailly) of non-utility generators to assess commercial/institutional and industrial CHP history and activity
2. Identify commercial/institutional and industrial applications best suitable for 1-10 MW gas turbine CHP systems

3. Identify states with high potential for 1-10 MW CHP applications and need for low emissions. Desirable attributes include:
   - relatively high electric rates
   - emissions regulations that require ultra-low NO_x levels (<2.5 ppm)
   - favorable history of implementing CHP project.

3.5 Current CHP Market and Applications

The first two topical reports of this project identified Combined Heat and Power (CHP) as the best application for gas turbine systems in the 1-10 MW size range with catalytic combustion. An understanding of existing combined heat and power sites (CHP) provides insights with respect to project sizes, prime mover technologies, locations, site applications, and the role of natural gas. The next sections explore existing CHP markets as a component of the analysis and summary of potential CHP market opportunities. Data presented on the current CHP market is based on analyses by Energy Nexus Group, Onsite Energy Corp., and the PA Consulting Hagler-Bailly database of non-utility generators.

Table 3-1 presents an estimate of the current use of natural gas and other fuels energizing US CHP projects in commercial, industrial and other sectors. The table summarizes 2,167 CHP projects with a capacity of 53,300 MW of electricity. Natural gas is used in 69% of the projects and represents 64% of the total CHP capacity.

Table 3-1: CHP Fuel Use by Sector

Sector	Coal		Natural Gas		Oil		Waste		Wood		Other	
Commercial/ Institutional	18 sites	440.1 MW	866 sites	3547.3 MW	30 sites	110.6 MW	25 sites	655.3 MW	4 sites	46.7 MW	37 sites	125.5 MW
Industrial	147 sites	7631.1 MW	484 sites	27939.0 MW	63 sites	1243.4 MW	84 sites	3249.6 MW	137 sites	232.2 MW	101 sites	3070.4 MW
Other	5 sites	245.5 MW	148 sites	2659.7 MW	11 sites	9.7 MW	2 sites	0.4 MW			5 sites	0.2 MW
Total	170 sites	8,317.3 MW	1498 sites	34146.0 MW	104 sites	1363.7 MW	111 sites	3905.3 MW	141 sites	2378.9 MW	143 sites	3196.1 MW

Source: Onsite Energy, PA Consulting Hagler-Bailly

Commercial and industrial markets have roughly the same number of projects; however, the industrial sites are almost 10 times as large on average. The fuel category, “other”, represents a wide variety of energy sources including propane, chemical off gases, mill byproducts, with wastewater plant biogases the largest component. “Waste” is primarily urban waste, factory waste, and mine waste. The Tables and discussion that follow will provide the details and origins of these summary statistics.

Table 3-2 presents the use of natural gas and other fuels with respect to the prime mover technology utilized. Natural gas is used by all prime mover technologies while coal, waste, and wood are generally limited to the boiler/steam turbine technology. Note that almost half the generating capacity is represented by 176 natural gas-fired combined cycle projects.

Table 3-2: CHP Technology Type vs. Fuel

Prime Mover	Coal		Natural Gas		Oil		Waste		Wood		Other	
Boiler/Steam Turbine	169 sites	8252.8 MW	67 sites	1401.2 MW	31 sites	443.2 MW	83 sites	2959.9 MW	141 sites	2378.9 MW	85 sites	2743.2 MW
Combined Cycle	1 site	64 MW	176 sites	25080.5 MW	3 sites	284.5 MW	9 sites	736.8 MW			1 site	27.0 MW
Gas Turbine			319 sites	7041.9 MW	9 sites	514.9 MW	8 sites	199.2 MW			9 sites	295.4 MW
Reciprocating Engines			920 sites	614.6 MW	61 sites	121.1 MW	11 sites	9.4 MW			35 sites	33.1 MW
Other			16 sites	7.8 MW							13 sites	97.3 MW
Total	170 sites	8,317.3 MW	1498 sites	34146.0 MW	104 sites	1363.7 MW	111 sites	3905.3 MW	141 sites	2378.9 MW	143 sites	3196.1 MW

Source: Onsite Energy, PA Consulting Hagler-Bailly

Natural gas is not only utilized by all CHP technologies, but it is also used across the CHP project size range spectrum as shown by Table 3-3. As expected, the preponderance of capacity is associated with the largest projects. Conversely, while there are many small projects, their total combined capacity is negligible. Natural gas is well represented across all size levels.

Table 3-3: CHP Size Range vs. Fuel Type

Size Range	Coal		Natural Gas		Oil		Waste		Wood		Other	
<1 MW	8 sites	3.0 MW	824 sites	138.8 MW	43 sites	16.9 MW	10 sites	2.3 MW	28 sites	12.6 MW	34 sites	10.0 MW
1.0 – 4.9 MW	21 sites	55.1 MW	246 sites	652.5 MW	33 sites	76.9 MW	20 sites	53.7 MW	28 sites	77.6 MW	23 sites	61.6 MW
5.0 MW - 19.9 MW	60 sites	594.9 MW	156 sites	1451.3 MW	16 sites	144.5 MW	28 sites	319.9 MW	48 sites	504.8 MW	23 sites	263.5 MW
> 20 MW	81 sites	7664.3 MW	272	31903.3	12 sites	1125.4 MW	53 sites	3529.4 MW	37 sites	1783.9 MW	63 sites	2861.0 MW
Total	170 sites	8,317.3 MW	1498 sites	34146.0 MW	104 sites	1363.7 MW	111 sites	3905.3 MW	141 sites	2378.9 MW	143 sites	3196.1 MW

Source: Onsite Energy, PA Consulting Hagler-Bailly

The relationship between CHP technology type and size range is presented in Table 3-4. Reciprocating engines dominate the under 1 MW size range while combined cycle facilities are almost always over 20 MW and combined cycle sites comprise almost 50% of the total capacity. Interestingly, the boiler/steam turbine and combustion turbine technologies are represented across all size ranges.

Table 3-4: CHP Technology Type vs. Size Range

Prime Mover	<1000 kW		1.0 - 4.9 MW		5.0 -19.9 MW		>20.0 MW		Total	
Boiler/Steam Turbine	50 sites	22.5 MW	113 sites	309.1 MW	183 sites	1907.7 MW	230 sites	15939.9 MW	576 sites	18179.3 MW
Combined Cycle			2 sites	8.6 MW	16 sites	141.7 MW	172 sites	26043.1 MW	190 sites	26193.3 MW
Gas Turbine	27 sites	16.4 MW	110 sites	345.3 MW	97 sites	930.7 MW	111 sites	6758.9 MW	345 sites	8051.3 MW
Reciprocating Engines	849 sites	138.22 MW	143 sites	306.8 MW	32 sites	266.9 MW	3 sites	66.3 MW	1027 sites	778.2MW
Other	21 sites	6.48 MW	3 sites	7.8 MW	3 sites	31.8 MW	2 sites	59.0 MW	29 sites	105.1MW
Total	947 sites	183.7 MW	371 sites	977.6 MW	104 sites	1363.7 MW	111 sites	3905.3 MW	2167 sites	53307.3 MW

Source: Onsite Energy, PA Consulting Hagler-Bailly

With respect to location, natural gas fired CHP projects are concentrated in several states with the top 7 states having 77 % of capacity and 77 % of sites, as follows:

- California – 5,664 MW, 640 sites
- Louisiana – 2,367 MW, 28 sites
- Massachusetts – 1,017 MW, 44 sites
- Michigan – 1,719 MW, 39 sites
- New Jersey – 2,691 MW, 158 sites
- New York – 4,061 MW, 156 sites
- Texas – 8,626 MW, 85 sites.

Table 3-5 presents a summarization of applications of CHP by 4 digit SIC (Standard Industrial Classification) Code. The table shows that CHP is broadly distributed over commercial, industrial and, even residential sites (39 sites). Natural gas is represented in almost all SIC application areas with solid waste and mining notable exceptions. As described previously, industrial sites are larger than commercial and other sites on average.

Table 3-5: CHP Customer Sector versus Fuel Type

Class	Application\Fuel	Coal	Natural Gas	Oil	Waste	Wood	Other	Totals
	SIC 4200 **Warehousing**		*4* **58.29**	*1* **3.00**	*1* **0.08**			*6* **61.37**
	SIC 4500 **Airports**		*7* **151.44**	*1* **5.50**			*1* **13.50**	*9* **170.44**
	SIC 4901 **Water Treatment**		*12* **116.03**	*1* **0.01**	*1* **3.00**		*12* **21.89**	*26* **140.93**
	SIC 4902 **Solid Waste**				*9* **372.45**		*2* **5.80**	*11* **378.25**
C	**SIC 4903** **District Energy/Utilities**	*3* **88.50**	*16* **728.39**	*1* **54.00**	*2* **31.70**	*1* **39.60**	*5* **12.50**	*28* **954.69**
O	**SIC 5411** **Food Stores**		*10* **1.38**					*10* **1.38**
M	**SIC 5812** **Restaurants**		*11* **0.91**	*1* **0.27**			*1* **0.07**	*13* **1.25**
M	**SIC 6512** **Commercial Buildings**	*1* **70.00**	*45* **109.60**	*2* **5.73**	*1* **28.00**		*3* **22.05**	*52* **235.38**
E	**SIC 6513** **Apartment Buildings**		*97* **95.38**	*1* **0.98**				*98* **96.35**
R	**SIC 7011** **Hotels**		*78* **25.74**	*2* **3.39**			*3* **1.04**	*83* **30.16**
C	**SIC 7200** **Laundries**		*76* **3.27**				*2* **0.03**	*78* **3.30**
I	**SIC 7542** **Car Washes**		*2* **0.16**		*4* **0.15**			*6* **0.31**
A	**SIC 7990** **Health/Country Clubs**		*81* **163.06**	*3* **1.21**			*1* **0.03**	*85* **164.30**
L	**SIC 8051** **Nursing Homes**	*1* **1.00**	*72* **9.68**					*73* **10.68**
	SIC 8060 **Hospitals**	*1* **5.00**	*119* **413.16**	*8* **16.07**	*1* **55.00**	*1* **2.00**	*1* **0.15**	*131* **491.38**
	SIC 8211 **Schools**		*101* **13.69**	*1* **0.12**			*4* **0.42**	*106* **14.23**
	SIC 8220 **Colleges/Universities**	*8* **215.57**	*93* **1,103.90**	*8* **20.36**	*1* **62.00**	*1* **1.13**	*1* **11.00**	*112* **1,413.95**
	SIC 8400 **Museums**		*2* **3.79**					*2* **3.79**
	SIC 9100 **Government Facilities**	*4* **60.65**	*26* **501.45**		*3* **57.20**			*33* **619.30**
	SIC 9223 **Prisons**		*14* **48.00**		*2* **45.70**	*1* **4.00**	*1* **37.00**	*18* **134.70**
	Commercial Totals **Commercial Totals**	***18*** **440.72**	***866*** **3,547.31**	***30*** **110.62**	***25*** **655.28**	***4*** **46.73**	***37*** **125.48**	***980*** **4,926.13**

	SIC 01 Agriculture	*2* **257.84**	*14* **287.29**		*5* **201.29**	*1* **0.15**	*3* **0.52**	*25* **747.10**
	SIC 07 Agriculture Services		*1* **4.00**					*1* **4.00**
	SIC 10 Metal Mining	*1* **124.00**						*1* **124.00**
	SIC 12 Coal Mining				*6* **232.30**			*6* **232.30**
I	**SIC 14 Mining (except fuels)**		*4* **116.00**					*4* **116.00**
N	**SIC 20 Food**	*37* **982.82**	*105* **3,362.90**	*12* **46.40**	*18* **154.43**	*5* **47.13**	*1* **0.70**	*178* **4,594.37**
D	**SIC 21 Tobacco**	*4* **129.48**			*1* **1.50**			*5* **130.98**
U	**SIC 22 Textiles**	*10* **331.75**	*7* **274.80**	*1* **12.20**			*4* **31.76**	*22* **650.51**
S	**SIC 24 Wood**	*1* **44.00**	*5* **180.62**	*1* **0.70**		*70* **543.43**	*3* **37.50**	*80* **806.25**
T	**SIC 25 Furniture**	*1* **63.00**				*7* **5.02**		*8* **68.02**
R	**SIC 26 Paper**	*43* **1,543.56**	*69* **2,791.58**	*12* **276.06**	*2* **169.00**	*44* **1,617.83**	*50* **2,154.52**	*220* **8,552.54**
I	**SIC 27 Printing**		*8* **16.68**	*1* **2.50**				*9* **19.18**
A	**SIC 28 Chemicals**	*32* **2,598.98**	*127* **13,917.90**	*11* **118.07**	*12* **356.40**	*4* **85.63**	*26* **615.28**	*212* **17,692.26**
L	**SIC 29 Petroleum**	*2* **182.50**	*40* **3,397.71**	*5* **632.90**	*21* **1,284.05**		*5* **120.46**	*73* **5,617.62**
	SIC 30 Rubber	*4* **249.15**	*8* **533.50**			*2* **0.30**	*1* **4.00**	*15* **786.94**
	SIC 32 Stone, Clay, Glass	*1* **170.00**	*14* **528.37**	*1* **1.20**			*3* **74.00**	*19* **773.57**
	SIC 33 Primary Metals	*2* **842.00**	*15* **1,245.72**	*1* **0.10**	*14* **781.70**		*1* **3.00**	*33* **2,872.52**
	SIC 34 Fabricated Metals		*22* **76.58**	*2* **1.80**				*24* **78.38**
	SIC 35 Machinery	*3* **30.50**	*12* **97.88**	*2* **3.70**	*1* **7.50**	*1* **9.70**		*19* **149.28**
	SIC 36 Electrical Equipment		*4* **179.08**	*2* **1.30**				*6* **180.38**
	SIC 37 Transportation Equip.	*2* **53.00**	*12* **674.11**	*3* **81.20**				*17* **808.31**
	SIC 38 Technical Instruments		*2* **50.83**	*2* **8.26**				*4* **59.09**
	SIC 39 Misc. Manufacturing	*2* **28.50**	*15* **203.45**	*7* **57.02**	*4* **61.48**	*3* **23.00**	*4* **28.68**	*35* **402.12**
	Industry Totals **Industry Totals**	*147* **7,631.08**	*484* **27,939.00**	*63* **1,243.41**	*84* **3,249.64**	*137* **2,332.17**	*101* **3,070.41**	*1016* **45,465.70**

	SIC 13	*4*	*77*	*2*	*2*			*85*
	Crude Oil	235.60	2,608.37	8.80	0.37			2,853.14
	SIC 40	*1*	*1*					*2*
	Railroad Transport	10.00	5.00					15.00
O	SIC 46		*1*					*1*
	Pipeline Transport		17.00					17.00
T	SIC 48		*2*					*2*
	Communication		9.25					9.25
H	SIC 49		*1*					*1*
	Utility Services		6.20					6.20
E	SIC 50		*11*	*2*				*13*
	Trade		5.45	0.28				5.73
R	SIC 83		*10*					*10*
	Services		0.87					0.87
	SIC 86		*3*				*2*	*5*
	Non-Profits		1.36				0.16	1.52
	SIC 88		*32*	*4*			*3*	*39*
	Households		0.50	0.03			0.03	0.56
	SIC 89		*7*	*2*				*9*
	Misc. Services		0.88	0.33				1.21
	SIC 99		*1*					*1*
	Nonclassifiable		2.40					2.40
	No SIC		*2*	*1*				*3*
			2.41	0.25				2.66
	Other Totals	*5*	*148*	*11*	*2*		*5*	*171*
	Other Totals	245.50	2,659.67	9.68	0.37		0.19	2,915.41
TOTALS		*170*	*1498*	*104*	*111*	*141*	*143*	*2167*
TOTALS		8,317.30	34,145.97	1,363.72	3,905.29	2,378.90	3,196.07	53,307.25

Key:	
No. of Sites	*12*
Electric Capacity MW	6,000.26

SOURCE: ONSITE ENERGY CORP., PA CONSULTING HAGLER-BAILLY

Major commercial users are colleges/university campuses, district energy/utility facilities, and hospital-type facilities. Medical care facilities average 3.75 MW capacity per site. Colleges/universities average about 12.5 MW per site. Primary schools, on the other hand, have numerous sites but only average 135 kW per site.

Industrial CHP users can be found in most SIC industries with chemical and petroleum plants leading the way with paper mills, food processing plants, and metal working also large users. Natural gas is used across the industrial spectrum, including petroleum refineries and paper mills. The largest industrial user group of natural gas CHP is in chemical plants, which account for 50% of industrial natural gas use. Crude oil producers dominate the "Other Sector" of non-commercial and non-industrial users.

The following two sections provide more detailed information on the commercial/institutional and industrial CHP markets. Appendix A contains state-by-state breakdowns by fuel type, technology type, and commercial/industrial split.

3.5.1 Commercial/Institutional CHP Market

This section characterizes the 980 sites and 4,926 MW of identified CHP in the commercial sector according to the following characteristics:

1. Fuel use
2. Type of technology (prime mover)
3. Type of commercial application
4. State
5. Size of CHP system

3.5.1.1 Fuel Type

Natural gas is by far the most common fuel type comprising over 72% of the total. The next most important fuel type is *waste*. Waste includes a variety of fuels but is dominated by landfill gas and biogas from sewage treatment facilities. Coal, oil, wood, and other fuel types make up the remaining 15% of installed CHP capacity.

3.5.1.2 Type of Prime Mover

Table 3-6 characterizes the commercial sector CHP in terms of the prime mover. The largest share of capacity (42.8%) comes from combined cycle power plants consisting of a combustion turbine and a heat recovery steam generator (HRSG) that drives a backpressure or extraction steam turbine. These plants are capable of high efficiency and are typically used only in comparatively large installations. Boilers and steam turbines make up 27% of total capacity. Boilers can fire any fuel type, but they are the only type of technology today that can be used to generate power from solid fuels like coal, wood, and certain types of waste. Combustion turbines make up about 19% of installed capacity. Both combined cycle and combustion turbines are technically capable of burning a variety of gaseous or liquid fuels, but, in U.S. CHP applications, they nearly always burn natural gas. Reciprocating engines make up 10% of capacity but represent 79% of the total number of installations. Reciprocating engines are commonly used in smaller installations; the average size for operating engine CHP systems is 0.7 MW. The average size for all operating commercial CHP is 5 MW.

Table 3-6: Commercial Sector CHP by Prime Mover in terms of Capacity, Number of Sites, and Average Size

Prime Mover	Capacity MW	Share %	Sites	Share %	Avg. Size MW
Combined Cycle	2,110	42.8%	27	2.8%	78.1
Boiler/Steam	1,341	27.2%	60	6.1%	22.4
Combustion Turbine	933	18.9%	104	10.6%	9.0
Reciprocating Engine	506	10.3%	770	78.6%	0.7
Other/not specified	36	0.7%	19	1.9%	1.9
Total	4,926	100.0%	980	100.0%	5.0

3.5.1.3 Type of Commercial/Institutional Applications

The commercial and institutional sectors are comprised of a broad range of activities that include private and government services but not including manufacturing, mining, or agriculture. Commercial applications, typically but not exclusively, are based on energy use in buildings. Unlike the industrial sector that, on balance, reflect an electric load limited environment for CHP, the commercial sector is predominantly thermal load limited. This limitation can occur in two ways; either the thermal load is inadequate or it is highly seasonal, i.e., noncoincident with the electric load – as in the thermal needs for space heating. Another limitation of commercial applications is the more limited hours of operation compared to an industrial process operation. An office building may operate 3,500 hours per year compared to a refinery that is operated continuously, or 8,760 hours per year. High and fairly constant thermal loads and a high number of operating hours per year characterize the commercial applications that are favorable to CHP. CHP systems are also typically sized to operate on a baseload basis and utilize the electric grid for supplementary and backup power.

Figure 3-1 shows the installed capacity of CHP by commercial application. The top eight applications represent 90% of the commercial sector installed CHP. These top eight sectors are as follows:

1. Colleges and Universities – This is the number one commercial CHP application with 29% of the total installed capacity. Universities resemble district-heating systems for small cities. CHP systems in universities typically serve the power and thermal needs of a multi-building site.
2. District Energy/Utilities – About 20% of the total is for district energy or utility applications. These systems tend to be large, multi-megawatt facilities serving a variety of applications and buildings.
3. Government – Government use represents a broad range of activities and commercial/institutional buildings.

4. Hospitals – Hospitals are large facilities with around-the-clock operation and large, steady thermal and electric requirements. They typically have engineering and operating staff on-site to manage a CHP system.
5. Solid Waste – This is not a necessarily building energy application but reflects landfill or waste to energy projects with some form of heat recovery.
6. Offices – This is one of the largest types of commercial applications in terms of building space.
7. Airports – Nine major airports have CHP systems to serve multiple buildings. These systems are generally in the multi-megawatt size range.
8. Health/Sports Centers – Rounding out the top 90% of commercial applications are health clubs and sports centers. These facilities represent a good match of steady electric and thermal loads.

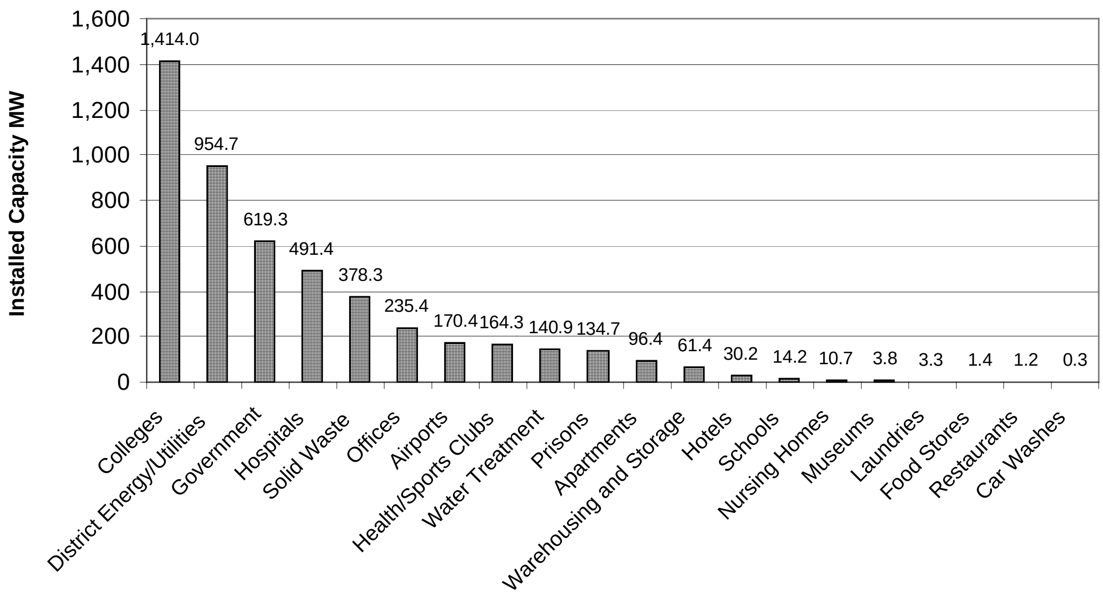


Figure 3-1: Capacity of Commercial CHP by Type of Commercial Application (MW)

Appendix B presents commercial CHP installations electric and thermal capacity by commercial sector and prime mover technology. CHP sites that utilize gas turbines in the 1-10 MW range are concentrated in the applications of Commercial Office Buildings (12 sites, 56 MW), Hospitals (30 sites, 97 MW), Colleges and Universities (39 sites, 563 MW), Government Facilities (7 sites, 22 MW), and Prisons (4 sites, 49 MW). Airports and District Energy applications have 3 sites and 23 MW combined. These segments can be characterized as large commercial or institutional markets.

3.5.1.4 Commercial/Institutional CHP Distribution by State

Commercial CHP is concentrated in the populous industrialized states of the Northeast, Midwest and California and Texas. In addition to large population and economic activity, these states typically have higher energy costs than the rest of the United States. Nearly half the total installed capacity is in three states – New York, California, and Pennsylvania. Adding in the next five largest states – Texas, Wisconsin, Michigan, New Jersey, and Florida – brings the cumulative share up to 75%.

With regard to gas turbine sites in the 1-10 MW range, California has the largest concentration with 35 sites making up 318 MW. New Jersey has the next highest concentration with 12 sites making up 75 MW. Michigan (7 sites, 68 MW), Connecticut (7 sites, 45 MW), Texas (5 sites, 49 MW), Illinois (5 sites, 27 MW), and Pennsylvania (4 sites, 21 MW) make up the majority of remaining gas turbine based CHP in the 1-10 MW range. A limited number of sites are located in Massachusetts, Florida, Ohio, Tennessee, and New Mexico.

3.5.1.5 Commercial/Institutional CHP Distribution by Prime Mover

Table 3-7 shows the size breakdown of commercial CHP by prime mover. Over 70% of the existing facilities are under 1 MW. Most of these small systems are powered by reciprocating engines. While the number of sites is dominated by the smaller sized systems, the total capacity impact of these small systems is comparatively small. The majority of the CHP capacity comes from the smaller number of large systems. There are 63 sites with capacities greater than 20 MW – including combustion turbine, combined cycle, and boiler/steam systems. These 63 large sites make up 77% of the existing commercial sector CHP capacity.

Table 3-7: Commercial Sector CHP by Size Range and Prime Mover (Sites)

Size Range	Boiler/ Steam	Combined Cycle	Combust. Turbine	Recip. Engine	Other	Total
0 – 999 kW	7		20	662	16	705
1.0 – 4.9 MW	15		42	83		140
5.0 – 9.9 MW	4	3	16	16	1	40
10.0 – 14.9 MW	3		11	7	2	23
15.0 – 19.9 MW	7		2			9
20.0 – 29.9 MW	5	6	5	2		18
30.0 – 49.9 MW	8	5	6			19
50.0 – 74.9 MW	11	4				15
75.0 – 99.9 MW		2	2			4
100 – 199 MW		5				5
200 – 499 MW		2				2
Total	60	27	104	770	19	980

The CHP sites tabulated include some multi-unit sites. The gas turbine based sites in the 1-10 MW range represent 58 sites and approximately 215 MW.

3.5.2 Industrial CHP Market

The industrial CHP market profile was developed to understand the technologies and applications that comprise existing CHP capacity and to provide insight into future market development. As was done in the commercial CHP review, the PA Consulting Hagler-Bailly database was used to characterize the existing industrial CHP base. The specific industrial sectors reviewed are listed along with two-digit SIC number in Appendix C. Figure 3-2 provides a summary perspective on industrial CHP. Several conclusions can be immediately drawn from the existing Industrial CHP capacity.

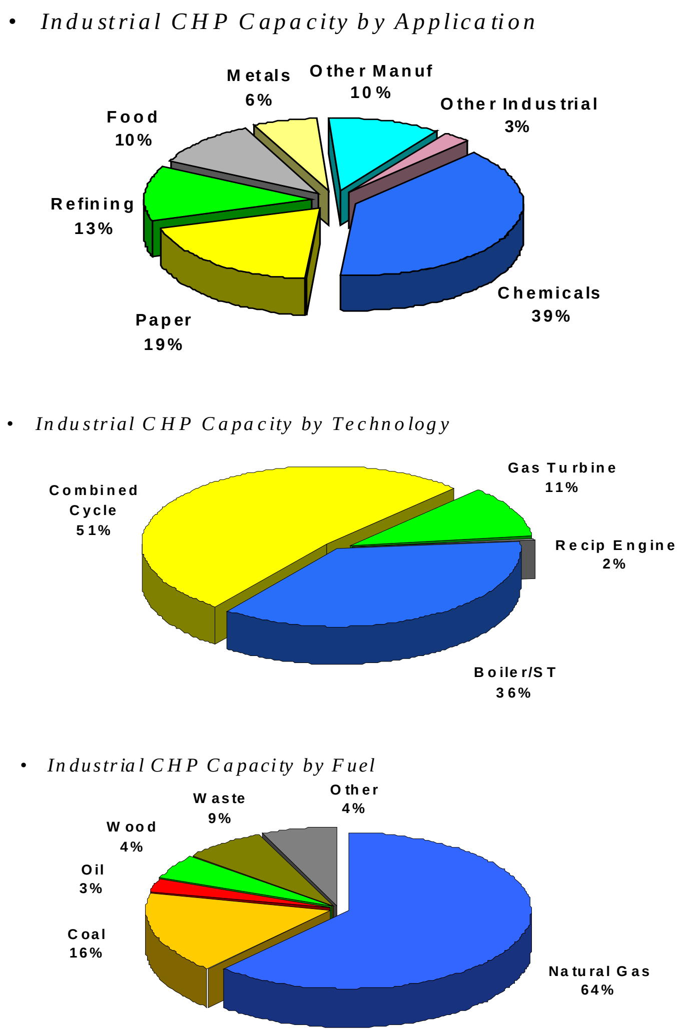


Figure 3-2: Existing Industrial CHP Capacity - 45,466 MW (1999)

Existing industrial CHP capacity is concentrated in a few industries. CHP facilities can be found in all manufacturing industries except Apparel Manufacturing and Leather and Tanning. However, Paper and Allied Products, Chemicals and Allied Products, and Petroleum Refining and related Products (SIC Groups 26, 28 and 29 respectively) combined represent more than two thirds of the total electric and steam capacities at existing industrial CHP installations.

In industrial applications, gas turbines can use their high quality recoverable exhaust heat as an advantage over competing technologies such as reciprocating engines. Some industries have power to heat demands that make gas turbines the most attractive CHP option. For example, paper industry CHP (SIC 26) has approximately the same steam capacity as the chemicals industry (SIC 28) but only half the electrical capacity, a reflection of the types of CHP systems employed. Consequently, the paper industry has relied primarily on boiler/steam turbine systems with low power to heat ratios; the chemical industry CHP capacity is primarily combustion turbine and combined cycle systems that have much higher power to heat ratios.

Existing industrial CHP depends on a variety of technologies and fuels. Natural gas is the primary fuel used for industrial CHP (61.3 % of capacity), but coal, wood and process wastes are used extensively by many industries (16.7 %, 5.1 %, and 7.1 % respectively). Accordingly, combustion turbines are the predominant technology in use representing 62.8 % of installed industrial CHP capacity in combined and simple cycle systems and are used by almost all industry segments. Boiler/steam turbines represent 36.4 % of installed industrial CHP capacity and are concentrated in the paper, chemicals and primary metals industries. In terms of number of facilities, reciprocating engines are used in over 161 sites (almost 16 % of facilities), primarily in the food, chemicals and fabrication and equipment industries.

Large systems account for most existing industrial CHP capacity. Table 3-8 provides data on size by prime mover technology. Gas turbine based CHP is concentrated in the sectors shown in Table 3-9. There is great variation in site electrical capacity at existing industrial CHP facilities, however, 80 % of existing capacity is represented by facilities of 50 MW and greater. Two thirds of the coal is used in systems over 100 MW size. Reciprocating engines predominate in facilities below 1 MW, and are used extensively in facilities up to 5 MW. Combined cycle systems dominate the larger facilities. Appendix D shows further detailed data on the industrial CHP.

Table 3-8: Existing Industrial CHP Size Range by Prime Mover Technology

Prime Mover	<1000 kW		1.0 - 4.9 MW		5.0 - 9.9 MW		10 .0 - 14.9 MW		15.0 -19.9 MW		>20.0 MW	
Boiler/Steam Turbine	43 sites	19 MW	97 sites	271 MW	86 sites	575 MW	46 sites	535 MW	36 sites	611 MW	202 sites	14581 MW
Combined Cycle			2 sites	9 MW	6 sites	41 MW	4 sites	52 MW	1 site	16 MW	144 sites	23543 MW
Gas Turbine	4 sites	2 MW	56 sites	187 MW	29 sites	217 MW	8 sites	90 MW	10 sites	165 MW	72 sites	4253 MW
Reciprocating Engines	101 sites	36 MW	50 sites	100 MW	6 sites	40 MW	2 sites	22 MW	1 site	15 MW	1 site	20 MW
Other	4 sites	2 MW	3 sites	8 MW							2 sites	69 MW
Total	152 sites	60 MW	208 sites	574 MW	127 sites	872 MW	60 sites	699 MW	48 sites	806 MW	421 sites	42466 MW

Source: Onsite Energy, PA Consulting Hagler-Bailly

Table 3-9: Industrial Gas Turbine CHP

SIC	Sector	Gas Turbine CHP Sites	Gas Turbine CHP Capacity	Average Site Capacity (MW)
29	Petroleum Refinery	30	1380	46.0
26	Paper	21	837	39.9
28	Chemical	63	1838	29.2
14	Mining Non-metallic	2	53	26.5
32	Stone, Clay, Glass	5	101	20.2
39	Misc. Manufacturing	9	137	15.2
20	Food	34	497	14.6
10	Coal Mining	2	20	10
37	Transportation Equipment	4	28	7
30	Rubber and Plastic	1	4	4
24	Lumber and Wood	2	6	3
22	Textile	2	5	2.5
27	Printing and Publishing	2	5	2.5
37	Primary Metals	2	4	2
TOTAL/AVE		**179**	**4915**	**27.5**

CHP is an important resource to a number of states. Table 3-10 presents existing CHP capacity by state as a function of system prime mover. Texas has the most industrial CHP capacity followed by California, Florida, Louisiana, New Jersey and New York.

Table 3-10: Statewide Industrial CHP Capacity by Prime Mover Technology

State	Steam	CC	CT	Recip.	Other	Totals
AK	*2* **28**		*4* **51**	*3* **16**		*9* **95**
AL	*14* **556**	*2* **125**	*1* **40**			*17* **720**
AR	*6* **126**		*2* **38**			*8* **164**
AZ	*2* **82**	*1* **50**		*2* **7**		*5* **139**
CA	*33* **581**	*25* **1710**	*43* **1024**	*52* **46**	*1* **0**	*154* **3362**
CO	*2* **43**	*4* **429**	*4* **47**			*10* **519**
CT	*8* **236**	*2* **82**	*1* **5**	*5* **4**		*16* **327**
DE	*4* **89**					*4* **89**
FL	*25* **1494**	*7* **712**	*10* **293**			*42* **2499**
GA	*17* **490**	*1* **300**	*1* **2**	*2* **2**	*1* **2**	*22* **796**
GU	*1* **0**		*1* **50**			*2* **50**
HI	*7* **240**	*1* **180**	*1* **9**	*3* **1**		*12* **430**
IA	*8* **135**					*8* **135**
ID	*10* **120**		*3* **23**			*13* **143**
IL	*13* **314**	*2* **55**	*10* **176**	*8* **13**	*2* **6**	*35* **564**
IN	*8* **1123**		*1* **18**	*1* **4**		*10* **1145**
KS	*3* **8**		*1* **40**	*1* **10**		*5* **58**
KY	*1* **4**					*1* **4**
LA	*18* **1094**	*8* **1421**	*12* **732**	*2* **1**		*40* **3248**
MA	*13* **76**	*7* **941**	*4* **32**	*4* **5**		*28* **1053**
MD	*4* **232**	*1* **240**				*5* **472**
ME	*18* **745**					*18* **745**
MI	*23* **289**	*4* **1542**	*8* **59**	*6* **4**		*41* **1894**
MN	*13* **250**	*1* **262**	*1* **1**			*15* **513**
MO	*4* **44**	*1* **4**				*5* **48**
MS	*13* **345**		*3* **28**			*16* **373**
MT	*4* **68**					*4* **68**
NC	*29* **1064**	*2* **185**	*2* **8**			*33* **1258**
ND	*3* **24**					*3* **24**
NE	*1* **7**			*1* **0**		*2* **7**
NH	*3* **5**		*1* **1**	*1* **12**		*5* **18**
NJ	*11* **592**	*19* **2406**	*8* **46**	*18* **13**	*1* **1**	*57* **3057**
NM	*1* **33**		*1* **3**			*2* **37**
NV		*4* **310**		*1* **1**		*5* **311**
NY	*12* **366**	*21* **3003**	*8* **129**	*24* **29**	*1* **0**	*66* **3528**
OH	*12* **260**		*1* **7**	*4* **5**		*17* **271**

OK	*4* **456**	*2* **220**				*6* **676**
OR	*15* **109**	*2* **499**	*1* **49**			*18* **657**
PA	*35* **1261**	*4* **194**	*4* **109**	*9* **15**		*52* **1580**
PR			*3* **9**	*1* **20**		*4* **29**
RI		*1* **67**				*1* **67**
SC	*7* **374**	*2* **500**		*1* **7**		*10* **881**
TN	*16* **338**		*1* **24**		*2* **59**	*19* **421**
TX	*26* **719**	*27* **7157**	*29* **1467**	*5* **4**	*1* **1**	*88* **9349**
UT	*3* **5**		*1* **15**			*4* **21**
VA	*25* **1400**	*2* **476**	*2* **20**	*4* **12**		*33* **1907**
VT	*2* **21**		*1* **8**	*1* **0**		*4* **28**
WA	*8* **194**	*4* **590**	*3* **165**			*15* **949**
WI	*20* **409**		*1* **180**	*1* **1**		*22* **590**
WV	*2* **139**					*2* **139**
WY	*1* **7**		*1* **3**	*1* **0**		*3* **10**
Totals **Totals**	*510* **16591**	*157* **23660**	*179* **4912**	*161* **233**	*9* **69**	*1016* **45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

3.5.3 Historically Active CHP Sectors

The review of existing CHP facilities identified customer classifications and states that have implemented CHP, and have the electric and thermal demand that make gas turbines in the 1-10 MW range an attractive option. The sectors identified utilize both single and multiple unit systems.

In the commercial sector historically attractive customer classes are:

- Commercial Office Buildings
- Colleges/Universities
- Hospitals
- Government Facilities
- Prisons

In the industrial market historically attractive customer classes are:

- Food Industry
- Miscellaneous Manufacturing
- Stone/Clay/Glass

- Chemical Industry

From a state perspective, those that historically have been home to 1-10 MW gas turbine based systems include:

- California
- New Jersey
- Michigan
- Connecticut
- Illinois
- Massachusetts
- Texas

These sectors and states represent markets with past CHP activity that indicates that 1-10 MW gas turbines have been attractive alternatives. The next two sections of this report attempt to identify those states that in the 2001-2010 time frame may provide a viable commercial opportunity for gas turbine-based CHP systems in the 1-10 MW range equipped with catalytic combustion. The screening criteria for potential attractive market include economically competitive generation of electricity and emissions restrictions that require ultra-low NO_x emissions.

3.6 States with the Potential for Economic CHP in 1-10 MW Range

In the determination of benefits to the state of California, the cost of electricity (COE) from representative 1 MW, 5 MW, and 10 MW CHP gas turbine-based systems with catalytic combustion was calculated. The fully installed capital costs along with COE (based on 8000 hours of operation and $4.50/MMBtu natural gas prices) are presented in Table 3-11. The COE presented credits the CHP system with the value of heat recovered.

Table 3-11: Cost Characteristics of Representative Gas Turbine Based CHP with Catalytic Combustion

	1 MW	**5 MW**	**10 MW**
Installed Cost ($/kW)	1275	938	757
Cost of Electricity* (cents/kWh)	6.4	5.1	4.3

*Based on 8000 hours of operation, $4.50/MMBtu natural gas costs, and value of recovered heat

In order to identify statewide markets where 1-10 MW CHP has economic advantages, statewide average industrial costs of electricity were compared to the cost of electricity of the representative gas turbine based CHP systems with catalytic combustion. The large institutional and industrial sectors, identified in the previous sections as good candidate target markets, would likely have access to low industrial rate electricity. Statewide average industrial electricity prices for the year 2000 are shown in Table 3-12.

Table 3-12: State Average Industrial Electricity Costs

State	Average 2000 Industrial Electric Cost (cents/kWh)[1]
Alabama	3.9
Alaska	8.0
Arizona	5.0
Arkansas	4.2
California	5.6
Colorado	4.4
Connecticut	7.3
Delaware	4.8
Florida	4.9
Georgia	4.0
Hawaii	11.7
Idaho	3.1
Illinois	4.2
Indiana	3.8
Iowa	3.9
Kansas	4.5
Kentucky	3.0
Louisiana	5.0
Maine	6.3
Maryland	4.1
Massachusetts	8.1
Michigan	5.1
Minnesota	4.6
Mississippi	4.2
Missouri	4.5
Montana	3.0
Nebraska	3.6
Nevada	4.9
New Hampshire	9.3
New Jersey	6.8
New Mexico	4.8
New York	4.9
North Carolina	4.6
North Dakota	4.0
Ohio	4.5
Oklahoma	4.2
Oregon	3.4
Pennsylvania	4.3
Rhode Island	8.5
South Carolina	3.6
South Dakota	4.6
Tennessee	4.6
Texas	4.5
Utah	3.3
Vermont	7.3
Virginia	3.9
Washington	3.6
West Virginia	3.8
Wisconsin	4.0
Wyoming	3.4

1. Source: Energy Information Administration

States with average industrial electricity rates greater than 6.4 cents/kWh (the most expensive COE based on a representative 1 MW gas turbine based CHP system with catalytic combustion) include:

- Alaska
- California
- Connecticut
- Hawaii
- Massachusetts
- New Hampshire
- New Jersey
- Rhode Island
- Vermont

The one noteworthy state that is included in the above list by the virtue of unusual circumstances is California. The year 2000 average industrial electricity rate for California was 5.6 cents/kWh. The 2001 year-to-date average industrial rate through May 2001 was above 10 cents/kWh according to the Energy Information Administration. Given the recent power crisis in California, pending re-regulation and revisiting of rates, it is highly probable that the industrial electricity rates will be more than 6.4 cents/kWh. Consequently, California is included in the previous list of states.

3.7 Environmentally Constrained Areas

The requirements for the emission levels that catalytic combustion systems can achieve (<2.5 ppm NO_x) are geography-specific and currently limited to "environmentally constrained areas". Environmentally constrained areas include states in the ozone transport region of the Northeast, Northeast States for Coordinated Air Use Management (NESCAUM), Mid-Atlantic Regional Air Management Association (MARAMA) and other counties that have been identified as serious, severe and extreme non-attainment for ozone. More specifically, the environmentally constrained regions include:

- States in Ozone Transport Region (OTR) – Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, parts of Virginia, and District of Columbia.
- States in the NESCAUM area - Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, Rhode Island, and Vermont
- State in the MARAMA area – Delaware, District of Columbia, Maryland, New Jersey, North Carolina, Pennsylvania, and Virginia
- States with certain county designations with serious, severe or extreme non-attainment status – California, Illinois, Indiana, Texas, Wisconsin, Georgia, Louisiana, and Arizona

The first topical report from this project on commercialization requirements described the recent activities in California and Texas where very low emissions levels comparable to those from new large central station combined cycle plants would apply to CHP projects in the 1-10 MW range. This trend is likely to be followed by other air regulators.

3.8 Results

The objectives of this task were to: 1) provide a qualitative assessment of the United States CHP market for gas turbines in the 1-10 MW size range, 2) identify states with prevailing electric rates that could allow economic utilization of 1-10 MW gas turbine-based CHP projects with catalytic combustion, 3) identify states that have air emissions regulations that may require ultra-low emissions, and 4) recommend customer sectors and states that could be attractive initial target markets.

The screening criteria for selecting target markets included the following:

- States with relatively high electric rates
- States with emissions regulations that require ultra-low NO_x levels (<2.5 ppm)
- States and customer sectors with a favorable history of implementing CHP projects in the 1-10 MW size range

Table 3-13 provides a summary of the screening results based on the approach and data presented above on the existing CHP market.

Table 3-13: Target Market Screening Results

States with High Electric Rates	States in Environmentally Constrained Areas	States with Favorable History with CHP	Customer Sectors with Favorable History with CHP
Alaska California Connecticut Hawaii Massachusetts New Hampshire New Jersey Rhode Island Vermont	Arizona California Connecticut Delaware Illinois Indiana Louisiana Maine Maryland Massachusetts New Hampshire New Jersey New York Pennsylvania Rhode Island Texas Vermont Virginia Wisconsin	California New Jersey Michigan Connecticut Illinois Massachusetts Texas	Commercial Office Buildings Colleges/Universities Hospitals Government Facilities Prisons Food Industry Miscellaneous Manufacturing Stone/Clay/Glass Chemical Industry

3.9 Conclusions and Recommendations

As was noted in the topical report on commercialization requirements, a strategy based on CHP applications has several noteworthy advantages. From a technical and product positioning perspective, the electrical heat rates of gas turbines in the 1-10 MW size range face a competitive disadvantage when compared with reciprocating engines. However, gas turbines in this size range possess compelling advantages over reciprocating engines in both emissions (even more so with catalytic combustion) and the quality of recoverable waste heat. From an application perspective CHP has a track record of successful implementation across a broad range of customer classes (e.g., industrial, institutional, and commercial) and has produced well-documented efficiency, emissions, and economic benefits.

The results of this qualitative assessment indicate that the best opportunities for 1-10 MW gas turbine based CHP systems with catalytic combustion are in markets in California, the Northeast states of Connecticut, Massachusetts, New Hampshire, New Jersey, Rhode Island, and Vermont, and East Texas. These states can be characterized as having both high electric rates and strict emissions limits on power generation equipment.

While several commercial and industrial sectors were identified as having an existing base of CHP in the 1-10 MW range, we recommend that the large institutional sectors of Colleges/Universities, Hospitals, Government Facilities and Prisons be initially targeted. These customers tend to have lower economic hurdle rates than industrial customers do and have a tendency to value the societal benefits catalytic combustion offers. These recommendations are summarized in Table 3-14.

Table 3-14: Recommended Target Markets

Regions	**Customer Sector**
California Connecticut Massachusetts New Hampshire New Jersey Rhode Island Vermont East Texas	Colleges/Universities Hospitals Government Facilities Prisons

3.9.1 Factors Impacting Ultimate Market Penetration

The overall results of this project identified issues and concerns of key stakeholders, quantified the significant benefits to California from the potential utilization of catalytic combustion on industrial sized gas turbines, and identified potential markets to target in the early phases of commercialization. Catalytic combustion offers compelling benefits, and it is entering commercial production at a time with notable market opportunities.

While most analysts agree that CHP can be a very competitive energy option in a fully restructured market, there are a variety of institutional and market hurdles that are currently limiting CHP growth in the transition. Factors that could lead to more aggressive market penetration in the future include:

- Technology Improvements - Projects in this size range are currently marginal in many areas. Equipment and development costs are high and users perceive CHP to be a high risk, non-core investment. New technologies such as catalytic combustion are entering the market that promise to significantly improve CHP economics for small to medium facilities due to reduced capital costs, higher efficiencies, and inherently low emissions.

- Recognizing Environmental Benefits of CHP - It is becoming widely accepted that CHP offers inherent environmental benefits because of it's increased efficiency. Future market penetration could be increased by efforts underway to advance adoption of output-based emissions standards that promote deployment of efficient technologies such as CHP and to streamline the environmental permitting process for efficient CHP installations. These standards should recognize the total efficiency of CHP.

- CHP Initiatives - Financial incentives for CHP (e.g., investment tax credits) provided by either the federal or state governments are being discussed by various parties to promote CHP's efficiency and emissions benefits. The rationale for these incentives is that increased penetration of efficient CHP results in broad public benefits that accrue to the public at large.

- Increased Marketing Efforts - The competitive market has created a large number of energy service providers that will be aggressively marketing energy service options including CHP. With higher marketing efforts, market penetration rates will increase for a given level of economic value. As marketing efforts and government programs are implemented, customer confidence in the technology will increase, reducing the risk premium that has been placed on CHP projects.

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APPENDIX A: STATE BY STATE BREAKDOWNS OF CHP

Table A-1: Fuel Type by State

State	Coal	Natural Gas	Oil	Waste	Wood	Other	Totals
AK	*1*	*8*	*6*		*1*		*16*
	25.00	**55.65**	**24.54**		**2.60**		**107.79**
AL	*1*	*4*		*2*	*5*	*6*	*18*
	65.00	**167.62**		**12.00**	**159.26**	**319.38**	**723.26**
AR		*4*		*1*	*2*	*3*	*10*
		50.30		**9.50**	**22.50**	**94.00**	**176.30**
AZ	*1*	*18*	*1*				*20*
	60.00	**82.40**	**3.00**				**145.40**
CA	*7*	*640*	*5*	*12*	*15*	*27*	*706*
	313.00	**5,663.70**	**11.61**	**301.10**	**194.08**	**178.04**	**6,661.53**
CO	*1*	*15*		*1*		*1*	*18*
	40.00	**592.17**		**2.80**		**0.70**	**635.67**
CT	*1*	*55*	*9*	*2*	*1*		*68*
	181.00	**203.99**	**51.04**	**29.00**	**0.15**		**465.18**
DE	*2*			*1*		*1*	*4*
	36.00			**48.00**		**4.50**	**88.50**
FL	*3*	*23*	*3*	*4*	*3*	*20*	*56*
	810.00	**957.20**	**12.81**	**119.50**	**239.70**	**535.62**	**2,674.83**
GA	*4*	*5*	*1*		*6*	*6*	*22*
	97.50	**321.20**	**1.20**		**68.98**	**307.00**	**795.88**
GU			*2*			*1*	*3*
			50.01			**0.20**	**50.21**
HI	*2*	*5*	*5*	*6*			*18*
	244.50	**0.48**	**181.89**	**68.10**			**494.97**
IA	*5*	*7*			*2*		*14*
	120.78	**7.14**			**13.20**		**141.12**
ID	*2*	*2*			*8*	*2*	*14*
	9.06	**20.00**			**110.65**	**22.80**	**162.51**
IL	*13*	*43*	*2*	*1*		*3*	*62*
	329.02	**258.01**	**21.40**	**27.60**		**28.80**	**664.83**
IN	*5*	*6*	*1*	*3*		*1*	*16*
	785.42	**28.15**	**3.50**	**373.20**		**0.20**	**1,190.47**
KS		*6*					*6*
		58.06					**58.06**
KY		*1*			*1*		*2*
		0.40			**4.00**		**4.40**
LA		*28*	*1*	*6*	*2*	*5*	*42*
		2,366.87	**422.00**	**220.93**	**116.00**	**224.50**	**3,350.30**
MA	*3*	*44*	*13*				*60*
	31.65	**1,016.78**	**104.38**				**1,152.81**
MD	*1*	*2*		*2*	*2*	*1*	*8*
	10.00	**250.00**		**229.00**	**54.00**	**3.00**	**546.00**
ME	*1*		*4*		*11*	*5*	*21*
	85.00		**175.02**		**298.73**	**187.00**	**745.74**

MI	*10*	*39*		*4*	*7*	*3*	*63*
	207.50	**1,718.74**		**82.78**	**75.73**	**29.68**	**2,114.42**
MN	*8*	*5*		*1*	*2*	*3*	*19*
	163.50	**268.64**		**4.20**	**45.00**	**41.00**	**522.34**
MO	*5*	*5*			*2*		*12*
	95.60	**23.96**			**1.25**		**120.81**
MS		*4*		*1*	*8*	*4*	*17*
		32.72		**5.00**	**150.00**	**190.00**	**377.72**
MT	*1*	*1*		*1*	*1*	*2*	*6*
	1.93	**0.20**		**55.00**	**0.75**	**10.35**	**68.23**
NC	*21*	*3*	*1*	*1*	*3*	*5*	*34*
	842.05	**189.00**	**6.50**	**18.80**	**57.00**	**172.16**	**1,285.51**
ND	*2*			*1*			*3*
	19.30			**5.00**			**24.30**
NE	*1*	*2*				*1*	*4*
	6.50	**0.11**				**0.90**	**7.51**
NH		*1*	*5*		*4*		*10*
		0.60	**18.73**		**6.86**		**26.19**
NJ	*2*	*158*	*6*	*4*		*5*	*175*
	487.00	**2,691.24**	**55.65**	**192.00**		**4.18**	**3,430.07**
NM		*10*				*3*	*13*
		47.73				**2.42**	**50.16**
NV		*6*					*6*
		311.42					**311.42**
NY	*4*	*156*	*21*	*8*	*4*	*2*	*195*
	247.91	**4,060.87**	**61.83**	**171.55**	**55.67**	**2.94**	**4,600.76**
OH	*9*	*11*		*2*	*2*		*24*
	186.69	**15.73**		**52.50**	**21.50**		**276.42**
OK	*1*	*7*		*1*	*1*		*10*
	320.00	**358.54**		**16.80**	**5.00**		**700.34**
OR	*1*	*3*			*12*	*2*	*18*
	7.50	**548.40**			**88.52**	**12.50**	**656.92**
PA	*16*	*37*	*8*	*21*	*2*	*3*	*87*
	499.03	**612.54**	**67.81**	**912.06**	**33.00**	**44.21**	**2,168.64**
PR			*4*				*4*
			28.92				**28.92**
RI		*6*					*6*
		68.09					**68.09**
SC	*3*	*3*	*1*	*1*	*2*	*3*	*13*
	148.00	**507.29**	**42.50**	**15.00**	**42.50**	**217.00**	**972.29**
SD		*1*					*1*
		2.70					**2.70**
TN	*7*	*3*			*8*	*7*	*25*
	223.44	**15.40**			**110.32**	**118.80**	**467.96**
TX		*85*	*1*	*13*	*4*	*7*	*110*
		8,625.99	**0.24**	**799.75**	**121.24**	**281.56**	**9,828.78**

UT		*5*		*1*	*2*		*8*
		20.53		**0.85**	**4.54**		**25.92**
VA	*16*	*7*	*2*	*7*	*6*	*3*	*41*
	1,279.78	**605.72**	**6.00**	**70.00**	**96.71**	**24.80**	**2,083.01**
VT		*3*			*2*	*1*	*6*
		7.71			**20.50**	**0.14**	**28.35**
WA		*8*			*5*	*3*	*16*
		758.69			**105.00**	**89.28**	**952.97**
WI	*8*	*10*	*1*	*2*	*4*	*3*	*28*
	199.64	**547.65**	**10.00**	**1.28**	**46.98**	**48.20**	**853.75**
WV	*2*	*1*	*1*	*1*			*5*
	139.00	**0.24**	**3.15**	**62.00**			**204.39**
WY		*2*			*1*	*1*	*4*
		5.43			**7.00**	**0.23**	**12.66**
Totals	*170*	*1498*	*104*	*111*	*141*	*143*	*2167*
Totals	**8,317.30**	**34,145.97**	**1,363.72**	**3,905.29**	**2,378.90**	**3,196.07**	**53,307.25**

Key:	
No. of Sites	*12*
Electric Capacity MW	**6,000.26**

Table A-2: Technology Type by State

State	Boiler/Steam Turbine	Combined Cycle	Combustion Turbine	Reciprocating Engine	Other	Totals
AK	*2*		*6*	*8*		*16*
	27.60		**57.01**	**23.19**		**107.79**
AL	*14*	*2*	*2*			*18*
	555.64	**124.62**	**43.00**			**723.26**
AR	*6*		*2*	*2*		*10*
	126.00		**37.70**	**12.60**		**176.30**
AZ	*2*	*1*	*3*	*14*		*20*
	82.00	**50.00**	**2.29**	**11.11**		**145.40**
CA	*41*	*36*	*132*	*485*	*12*	*706*
	808.03	**2,160.84**	**3,492.36**	**197.25**	**3.04**	**6,661.53**
CO	*2*	*6*	*6*	*4*		*18*
	42.80	**468.20**	**123.47**	**1.20**		**635.67**
CT	*13*	*4*	*8*	*43*		*68*
	262.88	**142.80**	**50.60**	**8.90**		**465.18**
DE	*4*					*4*
	88.50					**88.50**
FL	*27*	*8*	*13*	*8*		*56*
	1,603.89	**739.06**	**310.47**	**21.41**		**2,674.83**
GA	*17*	*1*	*1*	*2*	*1*	*22*
	489.98	**300.00**	**1.60**	**2.30**	**2.00**	**795.88**
GU	*1*		*1*	*1*		*3*
	0.20		**50.00**	**0.01**		**50.21**
HI	*7*	*2*	*1*	*8*		*18*
	239.99	**244.50**	**9.10**	**1.38**		**494.97**
IA	*8*			*6*		*14*
	135.48			**5.64**		**141.12**
ID	*11*		*3*			*14*
	139.71		**22.80**			**162.51**
IL	*16*	*2*	*16*	*26*	*2*	*62*
	362.52	**54.60**	**203.66**	**38.21**	**5.84**	**664.83**
IN	*9*		*3*	*3*	*1*	*16*
	1,163.50		**20.48**	**6.30**	**0.20**	**1,190.47**
KS	*3*		*1*	*2*		*6*
	7.96		**40.00**	**10.10**		**58.06**
KY	*1*			*1*		*2*
	4.00			**0.40**		**4.40**
LA	*18*	*9*	*13*	*2*		*42*
	1,093.63	**1,499.32**	**756.48**	**0.87**		**3,350.30**
MA	*13*	*8*	*5*	*33*	*1*	*60*
	75.96	**1,005.00**	**53.65**	**17.85**	**0.35**	**1,152.81**

MD	*7*	*1*				*8*
	306.00	**240.00**				**546.00**
ME	*19*			*2*		*21*
	745.73			**0.02**		**745.74**
MI	*27*	*4*	*15*	*17*		*63*
	432.93	**1,542.46**	**127.35**	**11.69**		**2,114.42**
MN	*14*	*1*	*2*	*2*		*19*
	253.70	**262.00**	**6.45**	**0.19**		**522.34**
MO	*7*	*1*	*1*	*3*		*12*
	96.85	**4.00**	**15.45**	**4.51**		**120.81**
MS	*13*		*4*			*17*
	345.00		**32.72**			**377.72**
MT	*4*			*2*		*6*
	67.88			**0.35**		**68.23**
NC	*30*	*2*	*2*			*34*
	1,092.21	**185.00**	**8.30**			**1,285.51**
ND	*3*					*3*
	24.30					**24.30**
NE	*1*			*3*		*4*
	6.50			**1.01**		**7.51**
NH	*5*		*1*	*4*		*10*
	9.86		**0.60**	**15.73**		**26.19**
NJ	*14*	*20*	*20*	*119*	*2*	*175*
	690.53	**2,570.57**	**120.34**	**47.49**	**1.15**	**3,430.07**
NM	*1*		*3*	*9*		*13*
	33.30		**10.54**	**6.32**		**50.16**
NV		*4*		*2*		*6*
		310.00		**1.42**		**311.42**
NY	*22*	*28*	*12*	*132*	*1*	*195*
	553.01	**3,673.30**	**259.92**	**114.12**	**0.40**	**4,600.76**
OH	*13*		*4*	*7*		*24*
	260.69		**10.13**	**5.61**		**276.42**
OK	*4*	*2*	*1*	*3*		*10*
	455.80	**220.00**	**16.30**	**8.24**		**700.34**
OR	*15*	*2*	*1*			*18*
	108.52	**499.00**	**49.40**			**656.92**
PA	*44*	*5*	*8*	*27*	*3*	*87*
	1,575.37	**378.25**	**130.02**	**84.43**	**0.58**	**2,168.64**
PR			*3*	*1*		*4*
			8.89	**20.03**		**28.92**
RI		*1*		*5*		*6*
		67.00		**1.09**		**68.09**
SC	*10*	*2*		*1*		*13*
	465.00	**500.00**		**7.29**		**972.29**
SD				*1*		*1*
				2.70		**2.70**
TN	*16*		*4*		*5*	*25*
	337.76		**39.40**		**90.80**	**467.96**

TX	*27*	*30*	*36*	*16*	*1*	*110*
	719.80	**7,518.31**	**1,544.14**	**45.77**	**0.76**	**9,828.78**
UT	*3*		*1*	*4*		*8*
	5.39		**15.25**	**5.28**		**25.92**
VA	*26*	*3*	*2*	*10*		*41*
	1,439.99	**596.00**	**19.50**	**27.52**		**2,083.01**
VT	*2*		*1*	*3*		*6*
	20.50		**7.60**	**0.25**		**28.35**
WA	*8*	*4*	*3*	*1*		*16*
	194.28	**590.00**	**165.10**	**3.59**		**952.97**
WI	*22*	*1*	*3*	*2*		*28*
	420.17	**248.50**	**183.85**	**1.23**		**853.75**
WV	*3*			*2*		*5*
	201.00			**3.39**		**204.39**
WY	*1*		*2*	*1*		*4*
	7.00		**5.43**	**0.23**		**12.66**
Totals	*576*	*190*	*345*	*1027*	*29*	*2167*
Totals	**18,179.30**	**26,193.33**	**8,051.33**	**778.17**	**105.12**	**53,307.25**

Key:	
No. of Sites	*12*
Electric Capacity MW	**6,000.26**

Table A-3: Sector by State

State	Commercial	Industrial	Other	Totals
AK	*6*	*9*	*1*	*16*
	13.02	**94.52**	**0.25**	**107.79**
AL	*1*	*17*		*18*
	3.00	**720.26**		**723.26**
AR	*2*	*8*		*10*
	12.60	**163.70**		**176.30**
AZ	*14*	*5*	*1*	*20*
	5.81	**138.75**	**0.84**	**145.40**
CA	*447*	*154*	*105*	*706*
	850.79	**3,362.15**	**2,448.59**	**6,661.53**
CO	*6*	*10*	*2*	*18*
	110.20	**518.62**	**6.85**	**635.67**
CT	*48*	*16*	*4*	*68*
	132.81	**327.23**	**5.14**	**465.18**
DE		*4*		*4*
		88.50		**88.50**
FL	*14*	*42*		*56*
	175.75	**2,499.07**		**2,674.83**
GA		*22*		*22*
		795.88		**795.88**
GU	*1*	*2*		*3*
	0.01	**50.20**		**50.21**
HI	*6*	*12*		*18*
	64.92	**430.05**		**494.97**
IA	*6*	*8*		*14*
	5.64	**135.48**		**141.12**
ID	*1*	*13*		*14*
	20.00	**142.51**		**162.51**
IL	*24*	*35*	*3*	*62*
	101.06	**563.73**	**0.04**	**664.83**
IN	*5*	*10*	*1*	*16*
	45.75	**1,144.70**	**0.03**	**1,190.47**
KS		*5*	*1*	*6*
		57.96	**0.10**	**58.06**
KY	*1*	*1*		*2*
	0.40	**4.00**		**4.40**
LA		*40*	*2*	*42*
		3,247.90	**102.40**	**3,350.30**
MA	*30*	*28*	*2*	*60*
	97.13	**1,053.27**	**2.41**	**1,152.81**
MD	*3*	*5*		*8*
	74.00	**472.00**		**546.00**

ME	*2*	*18*	*1*	*21*
	1.14	**744.60**	**0.01**	**745.74**
MI	*21*	*41*	*1*	*63*
	219.62	**1,894.45**	**0.35**	**2,114.42**
MN	*3*	*15*	*1*	*19*
	9.55	**512.75**	**0.04**	**522.34**
MO	*6*	*5*	*1*	*12*
	72.90	**47.85**	**0.06**	**120.81**
MS	*1*	*16*		*17*
	4.35	**373.38**		**377.72**
MT	*1*	*4*	*1*	*6*
	0.15	**67.88**	**0.20**	**68.23**
NC	*1*	*33*		*34*
	28.00	**1,257.51**		**1,285.51**
ND		*3*		*3*
		24.30		**24.30**
NE	*2*	*2*		*4*
	0.98	**6.53**		**7.51**
NH	*4*	*5*	*1*	*10*
	8.37	**17.66**	**0.17**	**26.19**
NJ	*106*	*57*	*12*	*175*
	202.34	**3,057.01**	**170.72**	**3,430.07**
NM	*7*	*2*	*4*	*13*
	13.22	**36.67**	**0.27**	**50.16**
NV	*1*	*5*		*6*
	0.02	**311.40**		**311.42**
NY	*116*	*66*	*13*	*195*
	1,067.89	**3,527.65**	**5.22**	**4,600.76**
OH	*7*	*17*		*24*
	4.93	**271.49**		**276.42**
OK	*1*	*6*	*3*	*10*
	16.30	**675.80**	**8.24**	**700.34**
OR		*18*		*18*
		656.92		**656.92**
PA	*29*	*52*	*6*	*87*
	458.73	**1,579.60**	**130.32**	**2,168.64**
PR		*4*		*4*
		28.92		**28.92**
RI	*5*	*1*		*6*
	1.09	**67.00**		**68.09**
SC	*3*	*10*		*13*
	91.00	**881.29**		**972.29**
SD	*1*			*1*
	2.70			**2.70**
TN	*6*	*19*		*25*
	47.20	**420.76**		**467.96**
TX	*19*	*88*	*3*	*110*
	449.30	**9,348.62**	**30.87**	**9,828.78**

UT	*3*	*4*	*1*	*8*
	5.25	**20.64**	**0.03**	**25.92**
VA	*8*	*33*		*41*
	175.52	**1,907.49**		**2,083.01**
VT	*2*	*4*		*6*
	0.11	**28.24**		**28.35**
WA	*1*	*15*		*16*
	3.59	**949.38**		**952.97**
WI	*6*	*22*		*28*
	263.63	**590.12**		**853.75**
WV	*3*	*2*		*5*
	65.39	**139.00**		**204.39**
WY		*3*	*1*	*4*
		10.36	**2.30**	**12.66**
Totals	*980*	*1016*	*171*	*2167*
Totals	**4,926.13**	**45,465.70**	**2,915.41**	**53,307.25**

Key:	
No. of Sites	*12*
Electric Capacity MW	**6,000.26**

APPENDIX B: COMMERCIAL CHP INSTALLATIONS

Electric and Thermal Capacity by Application and Prime Mover

	Boiler/Steam	Combined	CombustionTur	Reciprocating	Other	Totals
Warehousing & Storage			*2* **56.00** *224*	*4* **5.37** *21*		*6* **61.37** *245*
Airports		*2* **137.00** *548*	*1* **14.00** *56*	*4* **5.76** *23*	*2* **13.68** *55*	*9* **170.44** *682*
Water Treatment			*1* **49.40** *198*	*25* **91.53** *366*		*26* **140.93** *564*
Solid Waste Facilities	*9* **372.45** *3,270*			*2* **5.80** *23*		*11* **378.25** *3,293*
District Energy/ Utilities	*7* **152.09** *1,577*	*6* **739.47** *1,919*	*2* **18.75** *95*	*10* **36.53** *146*	*3* **7.85** *33*	*28* **954.69** *3,770*
Food Stores				*10* **1.38** *6*		*10* **1.38** *6*
Restaurants				*12* **1.21** *5*	*1* **0.04** *0*	*13* **1.25** *5*
Commercial Office Buildings & Facilities	*4* **121.00** *1,085*		*12* **56.39** *323*	*34* **57.14** *229*	*2* **0.85** *3*	*52* **235.38** *1,640*
Apartment Buildings	*2* **38.00** *456*	*1* **34.00** *100*		*95* **24.35** *97*		*98* **96.35** *653*
Hotels			*4* **8.05** *65*	*77* **21.01** *81*	*2* **1.10** *4*	*83* **30.16** *151*
Laundries				*76* **3.20** *13*	*2* **0.10** *0*	*78* **3.30** *13*
Car Washes				*6* **0.31** *1*		*6* **0.31** *1*
Health & Country Clubs		*2* **149.80** *350*	*1* **0.11** *0*	*82* **14.39** *58*		*85* **164.30** *408*
Nursing Homes	*2* **1.23** *18*			*71* **9.46** *38*		*73* **10.68** *56*
Hospitals	*7* **69.45** *437*	*5* **229.41** *688*	*30* **96.72** *556*	*86* **95.00** *380*	*3* **0.80** *3*	*131* **491.38** *2,065*
Elementary & Primary Schools			*1* **0.06** *0*	*104* **13.97** *56*	*1* **0.20** *1*	*106* **14.23** *57*
Colleges & Universities	*15* **294.63** *2,775*	*7* **449.60** *1,037*	*39* **563.31** *2,439*	*49* **95.21** *389*	*2* **11.20** *45*	*112* **1,413.95** *6,685*
Museums				*2* **3.79** *30*		*2* **3.79** *30*
Government Facilities	*11* **242.55** *2,501*	*3* **342.50** *643*	*7* **21.70** *130*	*12* **12.55** *50*		*33* **619.30** *3,324*
Prisons	*3* **49.70** *515*	*1* **28.14** *85*	*4* **48.80** *226*	*9* **7.87** *31*	*1* **0.20** *1*	*18* **134.70** *858*
Totals **Totals** *Totals*	*60* **1,341.10** *12,634*	*27* **2,109.92** *5,370*	*104* **933.28** *4,313*	*770* **505.81** *2,044*	*19* **36.02** *146*	*980* **4,926.13** *24,507*

Key:	
Number of Sites	*12*
Electrical Capacity, MW	**42.67**
Thermal Capacity, MMBtu/Hour	*207*

APPENDIX C: INDUSTRIAL SECTORS REVIEWED

CHP installations in the following industries were reviewed:

SIC	Industry
01	Agriculture - Crops
07	Agriculture - Services
11	Metal Mining
12	Coal Mining
14	Mining - nonmetallic Minerals
20	Food & Kindred Products
21	Tobacco Products
22	Textile Mill Products
23	Apparel
24	Lumber & Wood Products
25	Furniture & Fixtures
26	Paper & Allied Products
27	Printing & Publishing
28	Chemicals & Allied Products
29	Petroleum Refining and Related Industries
30	Rubber & Misc. Plastic Products
31	Leather & Leather Products
32	Stone, Clay, Glass and Concrete
33	Primary Metals
34	Fabricated Metal Products
35	Industrial & Commercial Machinery
36	Electronic & Other Electrical Equipment
37	Transportation Equipment
38	Measuring, Analyzing and Controlling Instruments
39	Miscellaneous Manufacturing Industries

APPENDIX D: INDUSTRIAL CHP MARKET CHARACTERIZATION

Table 2-1 CHP Fuel Type by Industry SIC

SIC	Coal	Gas	Oil	Waste	Wood	Other	Totals
1	*2* **258** *1,862*	*14* **287** *1,050*		*5* **201** *1,593*	*1* **0** *2*	*3* **1** *2*	*25* **747** *4,509*
7		*1* **4** *12*					*1* **4** *12*
10	*1* **124** *868*						*1* **124** *868*
12				*6* **232** *2,535*			*6* **232** *2,535*
14		*4* **116** *804*					*4* **116** *804*
20	*37* **983** *9,141*	*105* **3,363** *9,848*	*12* **46** *428*	*18* **154** *2,113*	*5* **47** *708*	*1* **1** *3*	*178* **4,594** *22,241*
21	*4* **129** *1,078*			*1* **2** *2*			*5* **131** *1,080*
22	*10* **332** *2,757*	*7* **275** *728*	*1* **12** *50*			*4* **32** *147*	*22* **651** *3,682*
24	*1* **44** *440*	*5* **181** *446*	*1* **1** *3*		*70* **543** *6,785*	*3* **38** *432*	*80* **806** *8,106*
25	*1* **63** *250*				*7* **5** *26*		*8* **68** *276*
26	*43* **1,543** *14,788*	*69* **2,792** *11,955*	*12* **276** *2,423*	*2* **169** *1,415*	*44* **1,618** *15,838*	*50* **2,155** *20,345*	*220* **8,553** *66,764*
27		*8* **17** *65*	*1* **3** *10*				*9* **19** *75*
28	*32* **2,599** *19,607*	*127* **13,918** *34,819*	*11* **118** *720*	*12* **356** *3,047*	*4* **86** *648*	*26* **615** *5,503*	*212* **17,692** *64,344*
29	*2* **183** *1,298*	*40* **3,398** *9,224*	*5* **633** *1,496*	*21* **1,284** *6,094*		*5* **120** *1,126*	*73* **5,618** *19,238*
30	*4* **249** *1,996*	*8* **533** *1,257*			*2* **0** *5*	*1* **4** *60*	*15* **787** *3,318*
32	*1* **170** *1,190*	*14* **528** *1,525*	*1* **1** *5*			*3* **74** *740*	*19* **774** *3,460*
33	*2* **842** *5,895*	*15* **1,246** *3,598*	*1* **0** *0*	*14* **782** *6,282*		*1* **3** *45*	*33* **2,873** *15,820*
34		*22* **77** *693*	*2* **2** *8*				*24* **78** *701*
35	*3* **31** *460*	*12* **98** *948*	*2* **4** *15*	*1* **8** *113*	*1* **10** *150*		*19* **149** *1,686*
36		*4* **179** *373*	*2* **1** *6*				*6* **180** *379*
37	*2* **53** *530*	*12* **674** *1,489*	*3* **81** *234*				*17* **808** *2,253*
38		*2* **51** *173*	*2* **8** *121*				*4* **59** *294*
39	*2* **29** *303*	*15* **203** *762*	*7* **57** *208*	*4* **61** *532*	*3* **23** *263*	*4* **29** *127*	*35* **402** *2,195*
Totals **Totals** *Totals*	*147* **7,631** *62,463*	*484* **27,939** *79,769*	*63* **1,243** *5,727*	*84* **3,250** *23,726*	*137* **2,332** *24,425*	*101* **3,070** *28,530*	*1016* **45,466** *224,640*

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**
Steam Capacity, PPHx1,000	147,600

Table 2-2 Existing CHP by Prime Mover and SIC Industry

SIC	Steam	CC	CT	Recip.	Other	Totals
	7	*6*		*12*		*25*
1	**458**	**275**		**14**		**747**
	3,454	*1,000*		*55*		*4,509*
		1				*1*
7		**4**				**4**
		12				*12*
	1					*1*
10	**124**					**124**
	868					*868*
	4		*2*			*6*
12	**213**		**20**			**232**
	1,715		*820*			*2,535*
	1	*1*	*2*			*4*
14	**8**	**55**	**53**			**116**
	120	*440*	*244*			*804*
	77	*24*	*34*	*41*	*2*	*178*
20	**1,279**	**2,740**	**497**	**78**	**1**	**4,594**
	13,367	*6,045*	*2,519*	*306*	*4*	*22,241*
	5					*5*
21	**131**					**131**
	1,080					*1,080*
	12	*3*	*2*	*3*	*2*	*22*
22	**339**	**260**	**5**	**21**	**26**	**651**
	2,870	*600*	*24*	*84*	*104*	*3,682*
	74	*2*	*2*	*2*		*80*
24	**625**	**175**	**6**	**1**		**806**
	7,657	*400*	*44*	*5*		*8,106*
	8					*8*
25	**68**					**68**
	276					*276*
	173	*23*	*21*	*3*		*220*
26	**6,049**	**1,664**	**837**	**3**		**8,553**
	58,271	*4,105*	*4,377*	*11*		*66,764*
	1		*2*	*6*		*9*
27	**3**		**5**	**12**		**19**
	10		*20*	*45*		*75*

SIC	Steam	CC	CT	Recip.	Other	Totals
	76	*52*	*63*	*17*	*4*	*212*
28	**4,096**	**11,683**	**1,838**	**34**	**41**	**17,692**
	32,931	*24,146*	*6,968*	*136*	*163*	*64,344*
	19	*21*	*30*	*2*	*1*	*73*
29	**747**	**3,486**	**1,380**	**5**	**1**	**5,618**
	6,848	*7,468*	*4,901*	*18*	*3*	*19,238*
	8	*3*	*1*	*3*		*15*
30	**264**	**515**	**4**	**4**		**787**
	2,226	*1,047*	*29*	*16*		*3,318*
	5	*3*	*5*	*6*		*19*
32	**248**	**420**	**101**	**4**		**774**
	1,990	*1,005*	*448*	*17*		*3,460*
	20	*4*	*2*	*7*		*33*
33	**1,722**	**1,144**	**4**	**2**		**2,873**
	13,375	*2,403*	*33*	*9*		*15,820*
	2	*1*		*21*		*24*
34	**10**	**56**		**12**		**78**
	152	*500*		*49*		*701*
	5	*2*		*12*		*19*
35	**48**	**92**		**10**		**149**
	723	*920*		*43*		*1,686*
		1		*5*		*6*
36		**173**		**7**		**180**
		350		*29*		*379*
	2	*6*	*4*	*5*		*17*
37	**53**	**719**	**28**	**9**		**808**
	530	*1,574*	*116*	*33*		*2,253*
	1	*1*		*2*		*4*
38	**8**	**50**		**1**		**59**
	120	*170*		*4*		*294*
	9	*3*	*9*	*14*		*35*
39	**99**	**147**	**137**	**18**		**402**
	1,057	*465*	*600*	*73*		*2,195*
Totals	*510*	*157*	*179*	*161*	*9*	*1,016*
Totals	**16,591**	**23,660**	**4,912**	**233**	**69**	**45,466**
Totals	*149,640*	*52,650*	*21,143*	*933*	*274*	*224,640*

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**
Steam Capacity, PPHx1,000	147,600

Table 2-3 Existing Industrial CHP - Prime Mover by Fuel Type

	Coal	Gas	Oil	Waste	Wood	Other	Totals
Steam Boiler	*147* **7631**	*58* **1234**	*22* **365**	*64* **2308**	*137* **2332**	*82* **2720**	*510* **16591**
Combined Cycle		*144* **22611**	*3* **285**	*9* **737**		*1* **27**	*157* **23660**
Combution Turbine		*156* **3948**	*7* **507**	*8* **199**		*8* **258**	*179* **4912**
Reciproca-ting Engine		*123* **140**	*31* **87**	*3* **6**		*4* **1**	*161* **233**
Other		*3* **5**				*6* **64**	*9* **69**
Totals	*147*	*484*	*63*	*84*	*137*	*101*	*1016*
Totals	**7631**	**27939**	**1243**	**3250**	**2332**	**3070**	**45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

Table 2-4 Existing Industrial CHP by Size Range and Fuel

Size Range	Coal	Gas	Oil	Waste	Wood	Other	Totals
0 - 999 kW	*5* **2**	*90* **32**	*18* **9**	*3* **2**	*28* **13**	*8* **3**	*152* **60**
1 - 4.9 MW	*20* **54**	*112* **317**	*23* **53**	*15* **39**	*25* **71**	*13* **40**	*208* **574**
5.0 - 9.9 MW	*29* **188**	*50* **351**	*6* **45**	*11* **75**	*25* **177**	*6* **38**	*127* **872**
!0.0 - 14.9 MW	*13* **155**	*19* **219**	*3* **32**	*7* **81**	*11* **133**	*7* **79**	*60* **699**
15.0 - 19.9 MW	*11* **189**	*12* **195**	*2* **33**	*5* **86**	*12* **195**	*6* **108**	*48* **806**
20.0- -29.9 MW	*14* **336**	*24* **565**	*3* **70**	*9* **203**	*9* **195**	*20* **484**	*79* **1854**
30.0 - 49.9 MW	*13* **484**	*51* **2057**	*3* **130**	*11* **409**	*13* **519**	*20* **759**	*111* **4357**
50.0 - 74.9 MW	*11* **686**	*28* **1667**	*2* **105**	*11* **609**	*9* **545**	*12* **742**	*73* **4355**
75.0 - 99.9 MW	*6* **509**	*20* **1672**		*4* **359**	*2* **172**	*8* **671**	*40* **3383**
100.0 - 199.9 MW	*20* **3074**	*50* **7521**	*2* **345**	*8* **1388**	*3* **313**	*1* **148**	*84* **12789**
200.0 - 499.9 MW	*4* **1222**	*21* **7304**	*1* **422**				*26* **8948**
500.0 - 999.9 MW	*1* **732**	*4* **2314**					*5* **3046**
I,000+ MW		*3* **3724**					*3* **3724**
Totals	*147*	*484*	*63*	*84*	*137*	*101*	*1016*
Totals	**7631**	**27939**	**1243**	**3250**	**2332**	**3070**	**45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**

Table 2-5 Existing Industrial CHP: Size Range by Prime Mover

Size Range	Steam	CC	CT	Recip.	Other	Totals
0 - 999 kW	*43* **19**		*4* **2**	*101* **36**	*4* **2**	*152* **60**
1 - 4.9 MW	*97* **271**	*2* **9**	*56* **187**	*50* **100**	*3* **8**	*208* **574**
5.0 - 9.9 MW	*86* **575**	*6* **41**	*29* **217**	*6* **40**		*127* **872**
!0.0 - 14.9 MW	*46* **535**	*4* **52**	*8* **90**	*2* **22**		*60* **699**
15.0 - 19.9 MW	*36* **611**	*1* **16**	*10* **164**	*1* **15**		*48* **806**
20.0- -29.9 MW	*48* **1105**	*14* **364**	*15* **340**	*1* **20**	*1* **24**	*79* **1854**
30.0 - 49.9 MW	*57* **2165**	*19* **774**	*34* **1383**		*1* **35**	*111* **4357**
50.0 - 74.9 MW	*40* **2426**	*24* **1389**	*9* **541**			*73* **4355**
75.0 - 99.9 MW	*18* **1517**	*15* **1276**	*7* **590**			*40* **3383**
100.0 - 199.9 MW	*33* **4905**	*46* **7187**	*5* **697**			*84* **12789**
200.0 - 499.9 MW	*4* **1222**	*20* **7024**	*2* **702**			*26* **8948**
500.0 - 999.9 MW	*2* **1241**	*3* **1805**				*5* **3046**
I,000+ MW		*3* **3724**				*3* **3724**
Totals **Totals**	*510* **16591**	*157* **23660**	*179* **4912**	*161* **233**	*9* **69**	*1016* **45466**

Key:	
No. of Sites	*12*
Electric Capacity, MW	**26,000**